MASS BALANCE OF THE PEGASUS FIELD SIMPSON-ELLENBURGER PETROLEUM SYSTEM, MIDLAND BASIN, WEST TEXAS

A Thesis

by

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ABSTRACT

As demand for sustainable energy increases, earth scientists seek to meet this demand by economically producing hydrocarbons from petroleum systems. Petroleum systems are complex, therefore multidisciplinary basin modeling analyses are used to gain more information about their dynamic nature. In this study, a mass balance workflow is developed and implemented to identify the quality and quantity of hydrocarbons distributed throughout the Pegasus Field Simpson-Ellenburger petroleum system. Four hypotheses are tested in this analysis which include the variation of hydrocarbon migration direction, alteration of source rock richness, and modification of generation kinetics. Post-testing analyses will also identify the geologic processes and parameters that have the largest impact on modeled results.

Modeled results indicate approximately 400 million barrels of condensate oil are in place within the Pegasus Field Ellenburger reservoir. Variation of hydrocarbon expulsion and migration directions result in two possible methods for charging the Ellenburger trap. Downward vertical charge from the Simpson Group delivers enough hydrocarbon fluids to match oil in place estimates, but final oil API gravities are slightly higher than measured data. Similarly, horizontal intraformational charge from the Simpson Group also delivers enough hydrocarbon fluids to match oil in place estimates, but final oil densities are slightly higher than measured data. When more optimistic source rock richness values are applied, the volume of generated and expelled hydrocarbons compared to previous tests increase by a factor of 1.5 which provides

more than enough hydrocarbon volumes to match oil in place approximations. Final modeled API gravity are slightly lower compared to produce fluids. When hydrocarbon generation kinetics are altered, 1.5 times the amount of oil and significantly larger gas volumes are retained within the source rock. Expelled hydrocarbon values are reduced, yet the model suggests enough hydrocarbons are expelled to match oil in place approximations. Alteration of generation kinetics result in a final mixed oil API gravity that is lower compared measured data.

Seal formation, migration and accumulation, burial history, and timing of geologic events are the most critical geologic processes impacting the petroleum system. Critical parameters include source rock richness, thermal history, source rock generation kinetics, and migration fetch area.

DEDICATION

This project is dedicated first and foremost to my parents and brothers who have loved and supported me throughout my life and academic career. Secondly, to my second family, my friends, who never give up on me and continue to support me. Lastly, this project is dedicated to all of my mentors and classmates who have given me guidance and helped me succeed during my time at Texas A&M University.

ACKNOWLEDGEMENTS

Countless hours of work throughout my undergraduate and graduate degrees have resulted in an accumulation of knowledge and skill-sets that were ultimately applied to this thesis. Although much of the work for this thesis was accomplished individually, many people have guided and aided me in my effort to produce this document. Without these individuals, much of this work would not have been possible. I would like to acknowledge these people here.

First and foremost, I would like to thank Dr. John Pantano. John instilled a strong foundation of petroleum systems within me and guided me through the intricacies of basin modeling. I am very thankful for his patience and continuous support even during the times where I struggled the most. John never gave up on me and I am extremely grateful to have had the opportunity to learn from such a brilliant person. I am thankful for his support, and know his teachings will surely benefit me later in my career.

Next, I would like to acknowledge and thank Chevron Corporation both for their financial support, as well as their technical support within our basin modeling center. I am very grateful to be a Chevron Scholarship recipient and know that without their support none of this work would have been possible. Barry Katz and Tess Menotti from Chevron Corporation have continuously shown their unwavering support for my project and dedicated their time and expertise voluntarily to help shape this thesis. I am so thankful for all of the time, constructive criticism, and feedback they have offered me over the past two years.

I would also like to thank the committee members and professors who were critical in the development of my thesis. Drs. Mauro Becker and Andrea Miceli Romero analyzed my project and provided invaluable feedback that guided me through the later stages of my work. Their technical support and vast knowledge of petroleum systems was extremely helpful during hypothesis testing and allowed me to think critically during analysis of thesis results. They both helped me shape this thesis document, and I am very grateful for their continuous support. I would also like to acknowledge Dr. Yucel Akkutlu for his technical support of my thesis. His advice and guidance throughout my two years of graduate school were essential to my success. Lastly, I would like to thank my advisor Dr. Yuefeng Sun. Dr. Sun was gracious enough to chair my committee, and I am very thankful for all of his contributions to the project.

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I am very thankful for my parents Sandy and Jay Carlton, and my brothers Brian, Blake, and Brandon Carlton who have supported me throughout my academic career.

They pushed me to work hard, and to never give up on my dreams which was essential to my success at Texas A&M University.

Throughout my entire academic career, I have relied on many mentors to guide me towards my goal of working in the oil and gas industry. Although many names come to mind, I would like to acknowledge my career mentor Bill Howard. Throughout my time at Texas A&M, Bill has been directing me to make the right decisions to put myself in the best position to succeed. His advice over the past six years has been essential to my success, and I can not thank him enough for all of his support. I would also like to acknowledge Dr. Carlos Dengo who helped guide me through graduate school. Dr. Dengo is an excellent mentor to me and I greatly appreciate his advice and leadership.

Undoubtedly there are more people that I have forgotten to mention, but these are just a handful of the many people who supported me throughout graduate school. Thank you!

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Contributors

This work was supervised by a thesis committee consisting of an advisor Professor Yuefeng Sun of the Department of Geology and Geophysics and Professor Mauro Becker of the Department of Geology and Geophysics and Professor Yucel Akkutlu of the Department of Petroleum Engineering. All work for the thesis was completed independently by the student, in collaboration with Dr. John Pantano of the Department of Geology and Geophysics.

This study was made possible using online databases, software, and donated data. First, I would also like to acknowledge DrillingInfo and Wood Mackenzie for access to their online databases. Next, I would like to thank and acknowledge ZetaWare, Inc. for the basin modeling software licenses that were used in this analysis. Lastly, I would like to acknowledge and thank Dolan Integration Group for the regional surfaces they contributed to this project.

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1. INTRODUCTION

Over the past few decades, the demand for hydrocarbon energy has increased as discovered conventional resources steadily decline by production and consumption. To fill this gap, technological advances have led to the development of unconventional and hybrid hydrocarbon resources. In order to maximize the discovery of new hydrocarbon accumulations, the petroleum industry has invested heavily in basin modeling analyses and methodologies to gain more information regarding the complex nature of petroleum systems. Mass balance techniques have also been implemented in the past to better identify hydrocarbon resource potentials and the efficiency of petroleum systems (Baur, 2010; Katz et al., 1994). Although these techniques are typically applied to the exploration of hydrocarbon fields, they can also be applied to producing fields to gain a better understanding of proven petroleum systems. With a better understanding of these systems, earth scientists will be able to apply their findings and workflows to similar fields and basins around the world where risk and uncertainty are inherently greater. By learning more about petroleum systems and the hydrocarbon fluids held within them, earth scientists will be able to discover and establish sustainable energy resources for years to come.

The primary focus of this analysis is to develop and test a mass balance workflow that will identify the transfer of hydrocarbon masses through a petroleum system over the geologic evolution of a field. A mass balance analysis evaluates the quality and quantity of hydrocarbon fluids and their distribution throughout a petroleum system (Hantschel and Kauerauf, 2009). Mass balance analyses also compare total generated hydrocarbons and the amount of hydrocarbons accumulated in a trap (Peters and Cassa, 1994).

In this study, a workflow is executed using a combination of basin modeling software, conceptual models, and public data sources. During execution of this workflow, we will gain a better understanding of the critical geologic processes (e.g., subsidence, exhumation, faulting, unconformity events, etc.) and parameters (e.g., temperature, pressure, source rock richness, etc.) that impact the generation, transport, and storage of hydrocarbons. At the same time, masses of produced hydrocarbons, remaining hydrocarbon fluids in the subsurface, hydrocarbons lost during migration, remaining source rock potential, residual hydrocarbon fluids that will never be extracted, and hydrocarbon masses lost by leaking or spilling from the reservoir are calculated throughout the complete geologic history of the Midland Basin. With the help of sensitivity analyses, a Monte Carlo simulation is then used to quantify hydrocarbon charge volume variability while simultaneously identifying geologic parameters that have the largest influence on modeled results for this analysis. To demonstrate the applicability of the workflow, we apply the methodology presented in this analysis to the Pegasus Field Simpson Ellenburger petroleum system in the Midland Basin located in west-Texas. Although hydrocarbon masses are the object of interest, hydrocarbon volumes are commonly discussed throughout this study for better visualization of hydrocarbon resources present in the system.

The Pegasus Field is a stacked hydrocarbon field discovered in 1942 by the Magnolia Petroleum Company. Production from the Pegasus Field began in 1949 and has continued to produce to present day (Harbison, 1955 and Cargile, 1969). Located

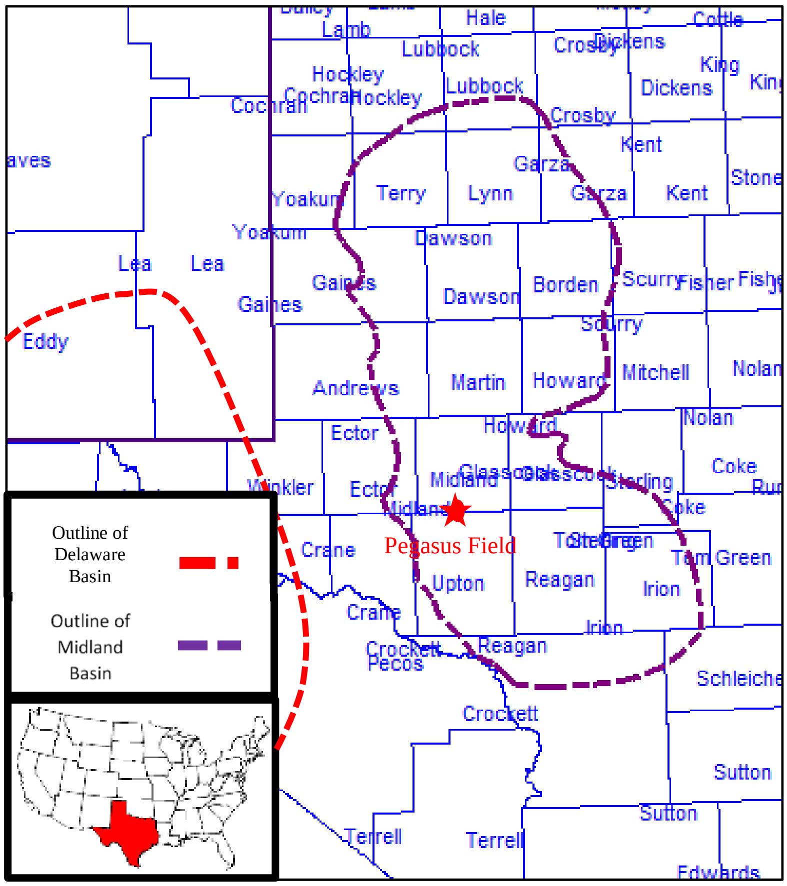

Figure 1. Location of the Pegasus Field.

in the center of the Midland Basin (**Figure 1**), this field contains a variety of stacked reservoirs found primarily in the San Andres, Spraberry, Wolfcamp, Pennsylvanian,

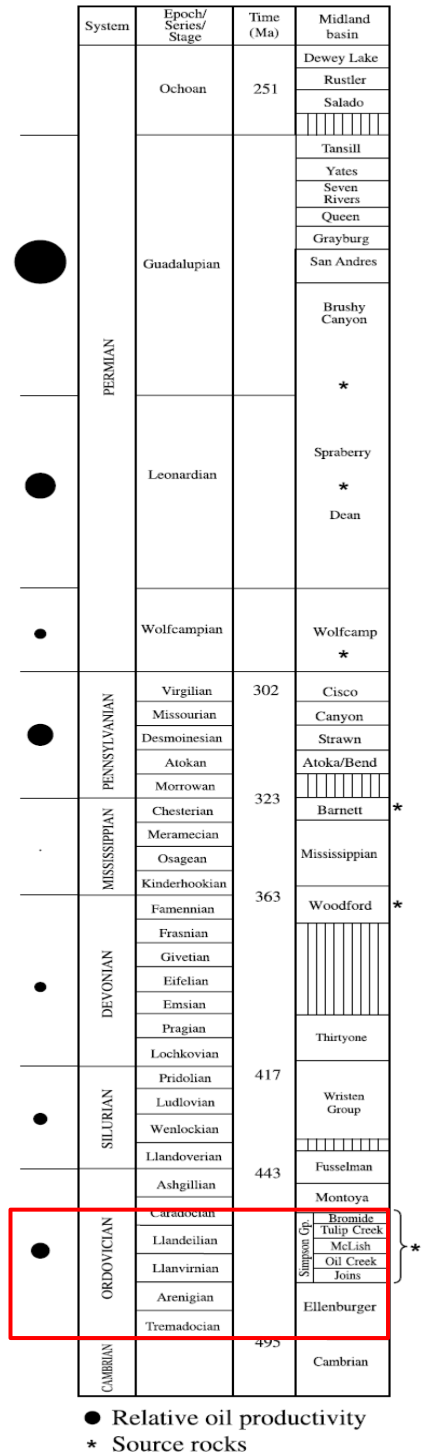

Figure 2. Complete stratigraphic section of the Midland Basin and the formations investigated in this study (red rectangle). Modified after Dutton, 2005. Reprinted by permission of the AAPG whose permission is required for further use. AAPG Bulletin, v. 89, no. 5. AAPG © 2005.

Devonian, Fusselman, and Ellenburger intervals (**Figure 2**) (Harbison, 1955; Cargile, 1969; Dutton, 2005). The Bureau of Economic Geology (BEG) estimated in 2005 that 32 MMbbl of recoverable oil reserves still remained in the Pegasus Field Ellenburger reservoir and according to DrillingInfo (2016) and Wood Mackenzie (2016), approximately 84 MMbbl of 53 API (American Petroleum Institute) gravity oil have been cumulatively produced from the Ellenburger reservoir system in 2016 (Dutton et al., 2005). Produced gas volumes were not reported during the early producing years of the Pegasus Field, and it is assumed that excess gas was flared or recirculated down hole for pressure maintenance.

In 1942, Robert Harbison with Stanolind Oil and Gas Co. conducted a detailed play assessment of the Pegasus Field for the West Texas Geological Society (WTGS). His assessment included a variety of data consisting of, but not limited to, structure maps, fluid property data, production data, and other reservoir parameters for the previously mentioned stacked reservoirs. Although Harbison's review was extensive, it focused more on reservoir characterization instead of the entire petroleum system. With a different perspective, almost 25 years later Katz et al. (1994) conducted a robust petroleum system analysis of the Simpson-Ellenburger Formations. This study was a regional analysis of major producing fields found in the Permian Basin. Their team conducted geochemical analyses that link Ellenburger produced oils to the Simpson source rock, as well as volumetric analyses to determine the overall efficiency of the petroleum system. According to their observations, we assume the Simpson source rock is the only source rock interval contributing hydrocarbons to the Ellenberger reservoir.

Katz et al. also provides a detailed analysis that contains crucial information prevalent to the study area of this analysis. Due to similar depositional environments of the Ordovician Simpson members, some data from their analysis is used as a proxy for values found in the deep basin petroleum system.

The area of interest for this analysis is considerably smaller than previous studies, averaging 90 square kilometers (km^2) and is confined to the center of the Midland Basin. With almost 70 years of work conducted for each zone, an immense collection of geology, engineering, and production data is available for the area of interest. Most of this data is publically available and is incorporated into an integrated 1-D basin model. By assimilating this data, a calibrated 3-D basin model is then created, and thus a comprehensive mass balance analysis can be conducted for the Pegasus Field. The Pegasus Field contains multiple formations that act as source rocks, migration pathways, reservoirs, and seals that are compiled into a stacked petroleum system. As mentioned previously, this analysis focuses solely on the deepest components that comprise the Ellenburger zone, more commonly referred to as the Simpson-Ellenburger petroleum system (Katz et al., 1994).

The foundation of the proposed workflow is rooted in the testing of multiple working hypotheses. Proposed working hypotheses do not follow any general theme, but are related to one another by the parameters or processes varied in each experiment. Each working hypothesis represents a possible scenario or modeling parameter that can be changed to best emulate the petroleum system. These scenarios are tested to determine which hypotheses are probable, possible, improbable, or impossible. The learnings that result from the mass balance, coupled with match or mismatch of present day parameters, are anticipated to be the most compelling outcomes that indicate the validity of a proposed hypothesis. The goal of this analysis is not to determine if a hypothesis is possible and probable, but rather to learn more about the petroleum system through successes and failures of hypothesis testing. A large variety of hypotheses can be tested using the model, but four ideas or concepts are chosen that are previously expected to have the largest impact on the petroleum system. These include the variation of hydrocarbon expulsion and migration direction, source rock richness, and generation kinetics.

In many analyses involving basin modeling, accuracy of the project and results are limited by the input data, modeling techniques, and validity of assumptions incorporated into the model. Speculative ill-defined assumptions can be misleading, therefore, in this study we seek to bridge this gap by explicitly defining the assumptions, variable correlations, and modeling parameters used during the mass balance workflow. A transparent analysis will provide better support to conclusions deduced from the mass balance and allow for consistent repeatability of the proposed workflow.

2. GEOLOGIC SETTING

The evolution of the Permian Basin has been extensively studied by researchers for more than 40 years (e.g. Galley, 1958; Adams, 1965; Wright, 1979; Frenzel et al., 1988; Hills, 1984; Horak, 1985; Hoak, 1988; Hills and Galley, 1988; Kerans, 1988; Sloss, 1988; Kerans, 1990). The Midland and Delaware Basins are subdivisions of the greater Permian Basin which are characterized as foredeep basins that developed during the late Mississippian and early Pennsylvanian at the south margin of the North American plate, north of the present-day Marathon-Ouachita thrust belt (Dutton et al., 2005; Hills, 1984; Frenzel et al., 1988) (**Figure 3**).

Prior to the structural evolution of the Midland and Delaware Basins, a shallow, intracratonic, down warped area deemed the Tobosa Basin was present in west-Texas and southeast New Mexico (Galley, 1958; Dutton, 2005). The Tobosa Basin existed during a relatively quiet tectonic period where the deposition of shelf carbonates and thin shales dominated the succession throughout much of the Ordovician. At this time, regional deposition of the Lower Ordovician Ellenburger Formation occurred consisting of thick (up to 1,700 ft.) sequences of mud-dominated carbonates, with localized grainstones deposited on a restricted shallow water carbonate ramp (Kerans, 1990). Middle Ordovician transgression later resulted in the deposition of shales, carbonates, and sandstones of the Simpson Group (Dutton, 2005). Platform carbonate deposition was dominant during the Silurian and Devonian until widespread black shales of the Mississippian were deposited regionally throughout Texas and Oklahoma (Hills, 1984).

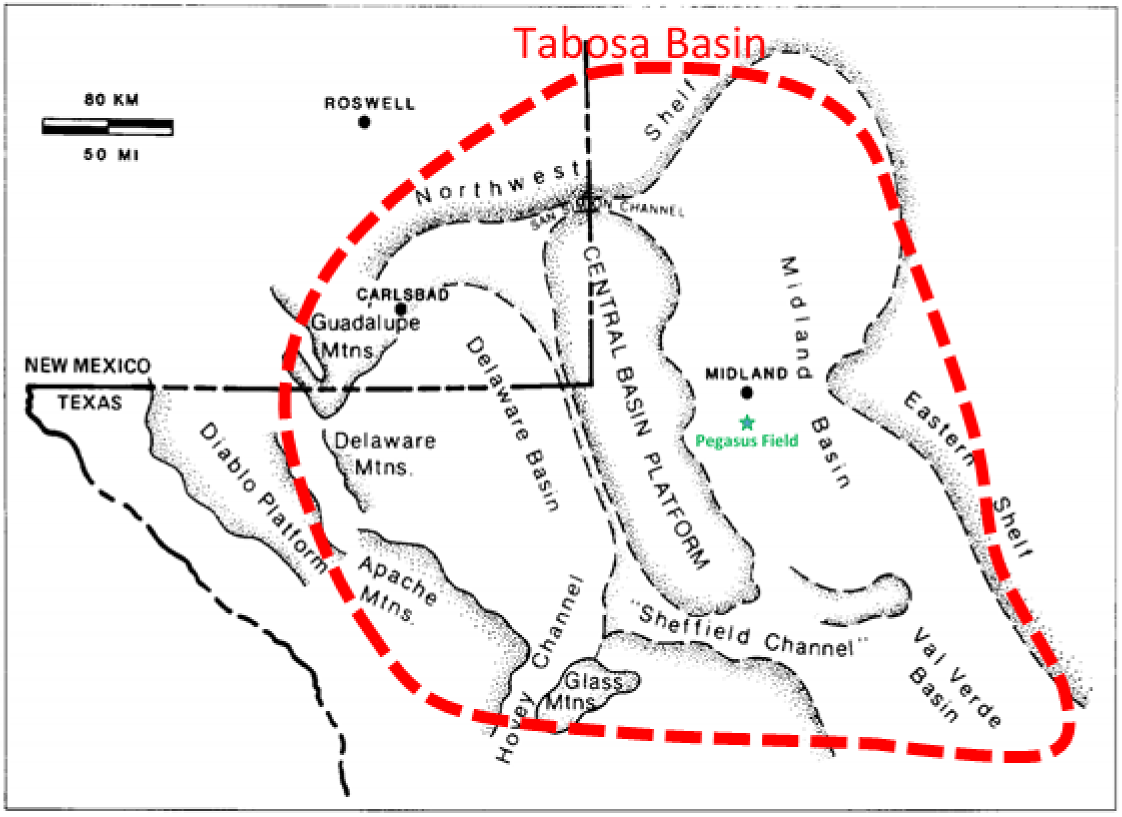

Figure 3. Map of the present day Permian Basin. The Pre-Pennsylvanian Tabosa Basin is outlined in red. Modified after Ward et al., 1986.

During the Late Pennsylvanian to Early Permian, compression driven by the Marathon-Ouachita thrust belt led to the creation of two basin-scale depressions, the Midland and Delaware Basins, separated by an exhumed carbonate platform, the Central Basin Platform (Hills, 1984). Rapid basin subsidence and continuous sediment influx persisted throughout multiple compression and relaxation events during the Triassic.

During the Jurassic to Early Cretaceous, a shallow intracratonic seaway flooded the North American continent and deposited thick accumulations of sediment across the Permian Basin (Sinclair, 2007). The basin was later uplifted during the Late Cretaceous Laramide orogeny, which eroded thousands of feet of sediment across the Permian Basin (Sinclair, 2007; Horak, 1985). During this process the Midland Basin was tilted creating angular unconformities between the Triassic and Cretaceous intervals. Basin and range extension across the Permian Basin occurred during the Late Oligocene which was then followed by minor sedimentation throughout the Late Cenozoic.

The Pegasus Field is approximately 10 km wide by 18 km long and is oriented roughly North-South (**Figure 4 and 5**). Structurally, the Pegasus Field Ellenburger Formation is a 20,000 acre four-domed anticline that straddles Midland and Upton Counties (Cargile, 1969). The anticline is bounded on the east and west flank by two late Mississippian normal faults that are also roughly oriented north-south. Overlying a granitic basement, the Ellenburger Formation is primarily a dark gray to light brown, finely crystalline, massive bedded dolomitic reservoir (Katz et al. 1994). Due to a relatively calm depositional environment, this reservoir is laterally continuous throughout most of the Permian Basin. Approximately 1,000 ft. thick in some areas, a large variety of lithofacies can be found within the formation including algal boundstone, intraclasitc packstone, laminate mudstones, burrowed mudstone, peloidal packstone, and ooid packstone-grainstones (Katz et al. 1994). Potential hydrocarbon reservoirs within the upper Ellenburger Group were produced by prolonged subaerial exposure and karstification of the carbonate platform prior to deposition of the Simpson

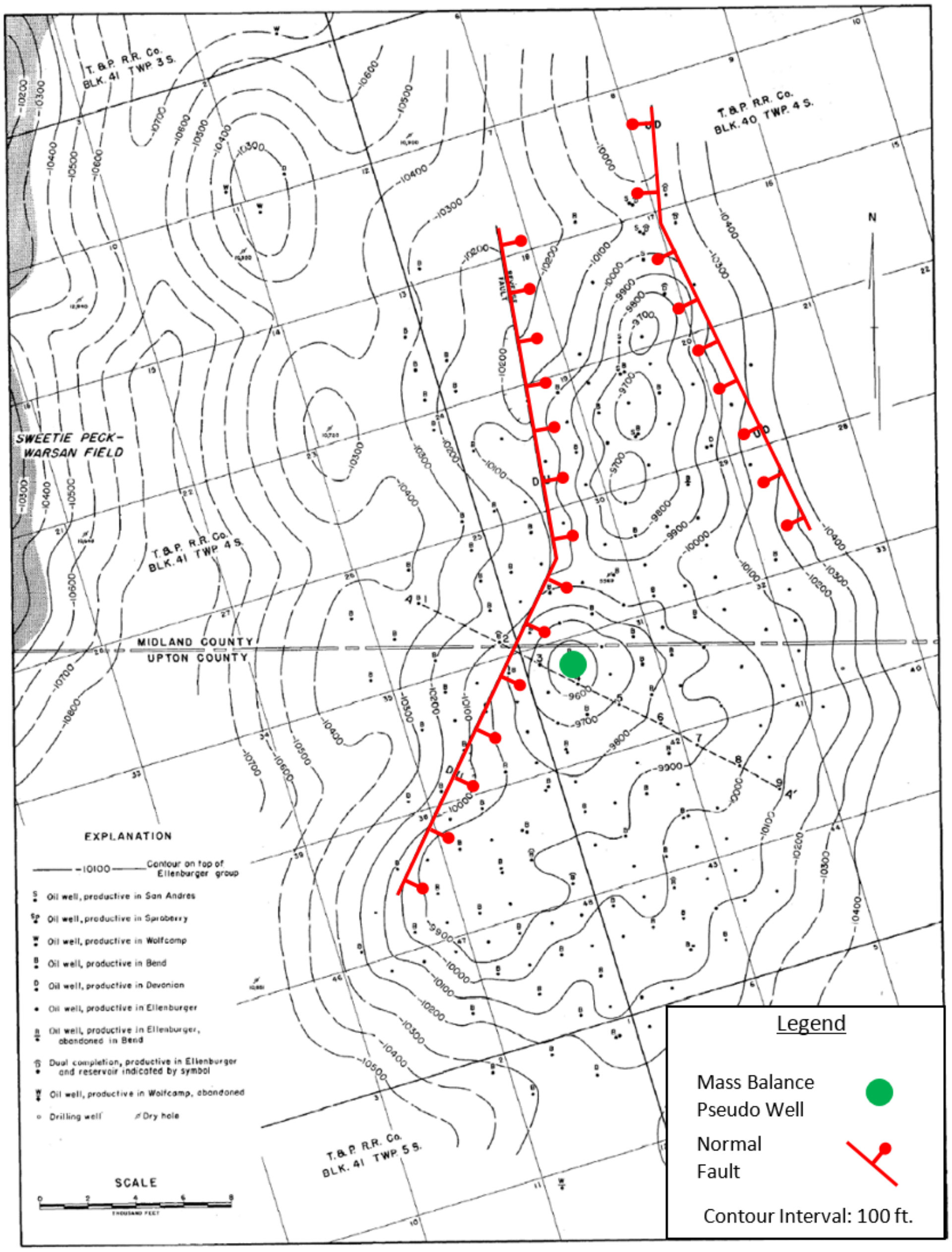

Figure 4. Structure map of the Pegasus Field Ellenburger Formation (Harbison, 1955). Reprinted by permission of the WTGS whose permission is required for further use.

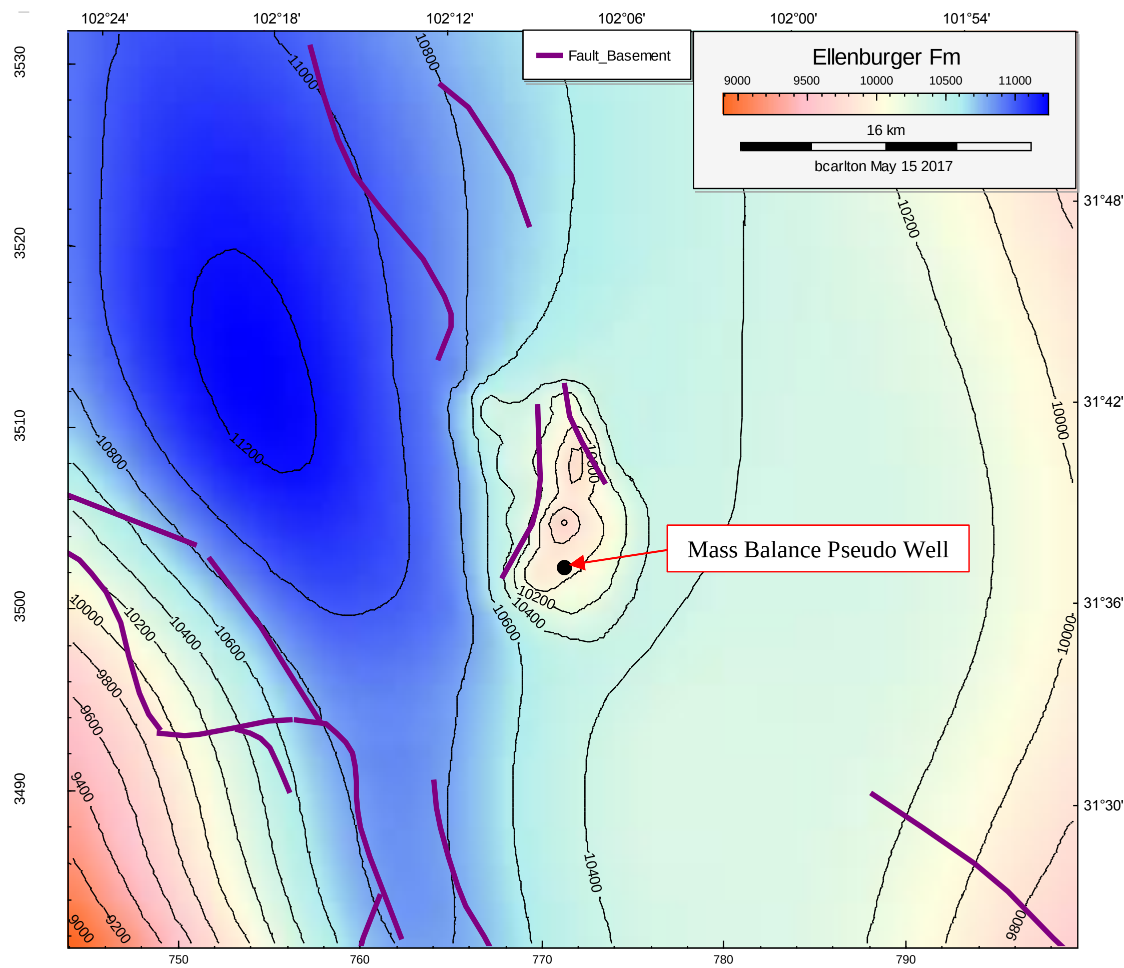

Figure 5. Regional Ellenburger Formation structure map with the mass balance pseudo well penetrating the top of the Pegasus Field.

Group during the Middle Ordovician (Ross, 1976; Kerans, 1988). Brecciated zones are distributed throughout the formation and vary in thickness (Cargile, 1969).

Directly above the Ellenburger Formation lies the Simpson Group which is generally described as a clay-rich carbonate and sandstone shale unit deposited during a marine transgression (Jones, 2009). Based on log analysis from WTGS, the Simpson Group measures 400 ft. thick in the Pegasus Field (Harbison, 1955). The Simpson Group can be divided into five formations including the Joins, Oil Creek, McLish, Tulip Creek, and Bromide (Decker and Merritt, 1931). The Joins Formation is comprised of gray to brown shaley limestones and dolomites and is slightly glauconitic at its base. The Oil Creek, McLish, and Tulip Creek Formations are mostly shale units with thin layers of fossiliferous limestones and calcareous sandstones. Lastly, light gray to brown Bromide massive limestone with minor shale interbeds are found near the top of the Simpson Group (Katz et al. 1994).

3. BASIN AND PETROLEUM SYSTEMS MODELING

Basin modeling is used to model dynamic geologic processes in sedimentary basins over geologic time spans (Hantschel and Kauerauf, 2009). Basin models forward simulate rock burial through geologic time to calculate and identify geologic processes such as heat flow, petroleum generation, migration, accumulation, etc. Similarly, petroleum systems models are digital data models used to understand and predict the dynamic nature of petroleum systems. These models also provide a complete and unique record of the generation, migration, accumulation and loss of hydrocarbons for a unique petroleum system through geologic time (Hantschel and Kauerauf, 2009; Tissot and Welte, 1984). Integration of both basin and petroleum systems models is used in this analysis to create a basin and petroleum system model of the Pegasus Field Simpson-Ellenburger system.

Trinity® (Version 5.65, 2015) basin modeling software by ZetaWare© is used in this study to model the Simpson-Ellenburger petroleum system. The Trinity T3® package is made up of three software packages, Trinity®, Genesis®, and KinEx 4.8® that are integrated together for basin and petroleum systems modeling. Trinity is used in this study to calculate hydrocarbon masses within the system using hydrocarbon generation, migration, and entrapment simulations. Genesis modeling software, which is primarily used for 1-D lithological and thermal modeling, can easily be incorporated into Trinity for 1-D model calibration. Lastly, KinEx 4.8 is a source rock maturity model that can be used to predict expelled hydrocarbon volumes, remaining source rock potentials, and other maturation parameters from source rocks. One of the key advantages of using this software is the large variety of ideas and hypotheses that can be quickly tested producing immediate results which can then be used to better understand petroleum systems.

All 3-D basin models begin initially as 1-D models where observed fluid and rock data can be incorporated for calibration purposes. A 1-D model is created in Genesis where all formations are assigned lithological values such as grain densities, mineralogy, average porosity, and permeability values to best emulate rocks within the system. This 1-D model is in the form of a “well-log” and will help define how heat moves through the system through time. Bottom Hole Temperature (BHT) data is collected for selected evenly distributed wells within the Pegasus Field. During the drilling process, circulation of drilling fluids cool the reservoir, therefore BHT values are corrected using an average temperature factor, and a temperature curve is created by best fitting data points to a linear geothermal gradient (**Figure 6)**. Also, a transient fixed temperature basal heat flow of 45 mW/m^2 from the base of the lithosphere is used in the model (Blackwell et. al, 2011). After the 1-D Genesis modeling is completed, the well is incorporated into Trinity software indicated by the “Mass Balance Pseudo Well” location in the center of the structure to calibrate the model (**Figure 5)**. Discussed in more detail later, a “layer cake” model was then built using regional surfaces.

With any petroleum system, we acknowledge that timing of petroleum system events is one of the most important factors that impact the generation, migration and

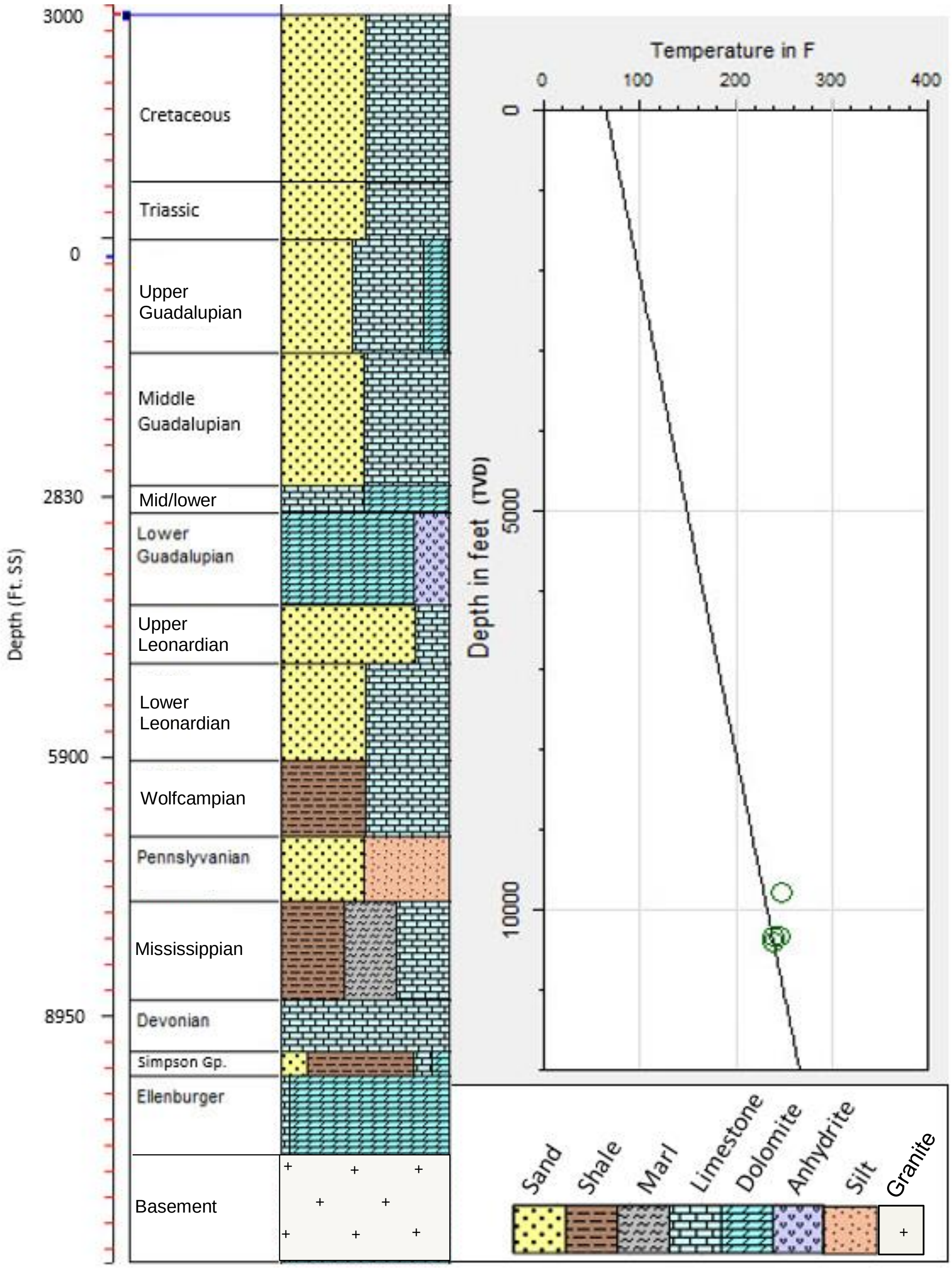

Figure 6. 1-D lithology (left) and temperature (right) calibration incorporated into Trinity Model.

entrapment of hydrocarbons throughout a system. Although a large amount of uncertainty is associated with the timing of petroleum system events, we initially use an

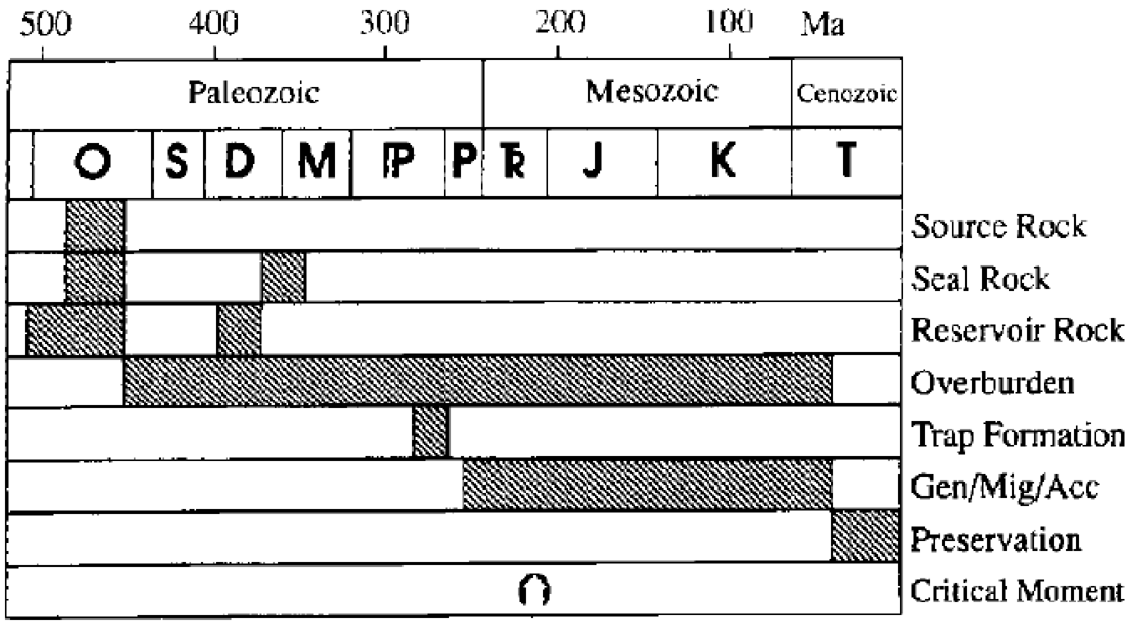

Figure 7. Petroleum system events chart showing temporal relationships of essential geologic elements and processes (Katz et al. 1994). Reprinted by permission of the AAPG whose permission is required for further use. AAPG Memoir 60. AAPG © 1994.

events chart produced by Katz et al. in 1994 (**Figure 7**) as a proxy to define the timing of each event for the Pegasus Field. After testing of hypotheses is completed, a revised timing of events chart is produced for the study area.

Figure 8 represents the burial history model for the Midland Basin. This model emulates the previously described complete structural evolution of the basin through time. **Figure 9** is a burial history produced from the study conducted by Katz et al. in

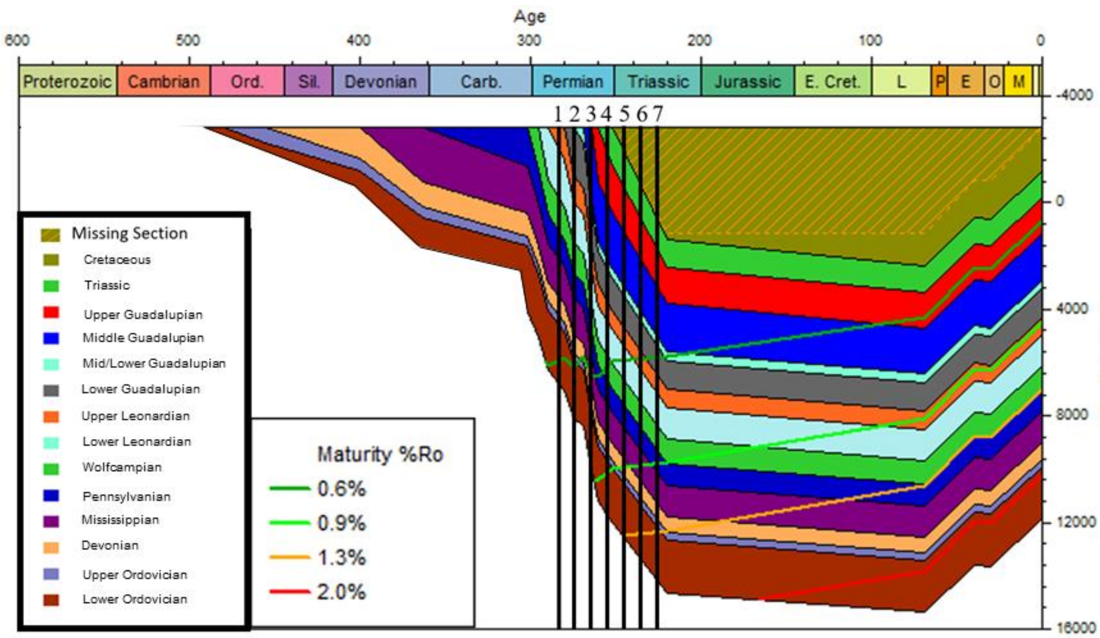

Figure 8. Midland Basin burial history model with proposed 10 million-year time step subdivisions highlighting punctual expulsion events.

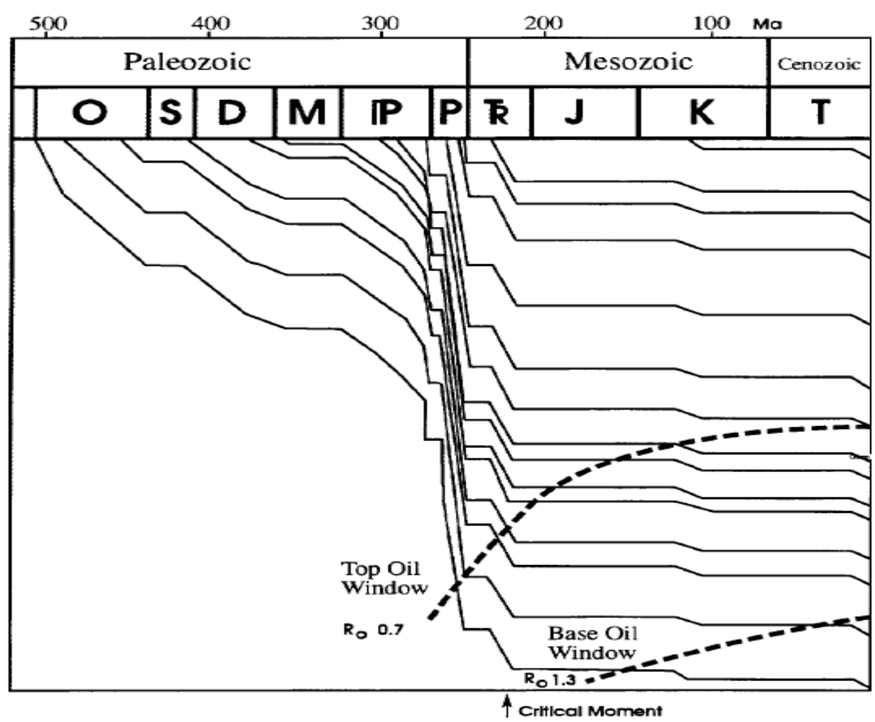

Figure 9. Burial history model for the Central Basin Platform (Katz et al. 1994). Reprinted by permission of the AAPG whose permission is required for further use. AAPG Memoir 60. AAPG © 1994.

1994. While this burial history diagram is used for the Central Basin Platform, similarities are apparent between both models. One primary difference between the burial history model proposed in this study compared to others is the deposition of a consistently thick and uniformly distributed sediment sequence at approximately 250 Ma. In this analysis, approximately 4,000 ft. of sediment is deposited and later eroded during exhumation of the basin (75 Ma) (Sinclair, 2007). Although this amount of missing section was measured in the Delaware Basin, due to a lack of data regarding the thickness of missing section in the Midland Basin the 4,000 feet of missing section is used as a proxy for this study area. Although the precise amount and distribution of missing section is highly uncertain, 4,000 ft. of sediment is needed to bury the petroleum system deep enough to expose source rock intervals to temperatures and pressures required to generate condensate type hydrocarbon fluids.

To calculate hydrocarbon masses present in the petroleum system and identify their distribution through time, simulations are run to generate and expel hydrocarbons. These simulations, referred to as “paleo-maturity maps”, can be generated during the geologic history of the Pegasus Field, and represent the punctual expulsion of hydrocarbons from the Simpson Group. Distinct hydrocarbon expulsion events, source rock richness distributions, and other maps can be generated using this method. Before hypothesis testing can be executed, time steps used for each paleo-maturity map simulation must be defined. Paleo-maturity maps are calculated at a distinct time, therefore time step subdivisions begin with the critical moment (initial hydrocarbon expulsion) and end when catagenesis or metagenesis of hydrocarbon fluids cease. For simulation purposes, subdivisions of ten million years are used to best represent each expulsion event as depicted in **Figure 8**. Subdivisions and the durations between proposed subdivisions can be altered during testing to best display expulsion, accumulation, and increased thermal maturity events.

Two structural surfaces were digitized and incorporated in the model from the WTGS report, one of which is the top structure map of the Ellenburger Formation with depths ranging 9600 ft. to 10700 ft. True Vertical Depth (TVD) (Harbison, 1955). The other surface is the Pennsylvanian Bend Formation approximately 3,000 ft. above (Harbison, 1955). Both formations have structures that are relatively similar to each other, therefore we assume conformable “layer cake geology” for most of the formations in this study (**Figure 10**). Despite this study’s focus in the Simpson-Ellenburger petroleum system, overlying formations are included to build a complete burial history model. All source rock intervals above the Simpson Group are assumed to be independent from the Simpson-Ellenburger system, and contribute little to no hydrocarbons into the Ellenburger reservoir.

Regional structural variability of the Ellenburger Formation is apparent throughout the Midland Basin. Although there are many ways of mapping the top of this reservoir unit, data surfaces were provided by Dolan Integration Group (2016). These surfaces represent a generalized structure across the entire Permian Basin for a 6 to 10-mile sampling radius from well-logs. Presented earlier, this regional surface was merged to the Pegasus Field digitized structural surface creating a new Ellenburger surface representing measured data from the two datasets. Depending on how each surface was independently mapped, the amount of detail and data points used between the two surfaces is most likely different. Simply stated, merging two surfaces that have variable degrees of sampling detail may have adverse effects on molded results, because the surfaces are directly used in hydrocarbon generation simulations. In an effort to best honor the provided data while making the surfaces geologically reasonable, the merged

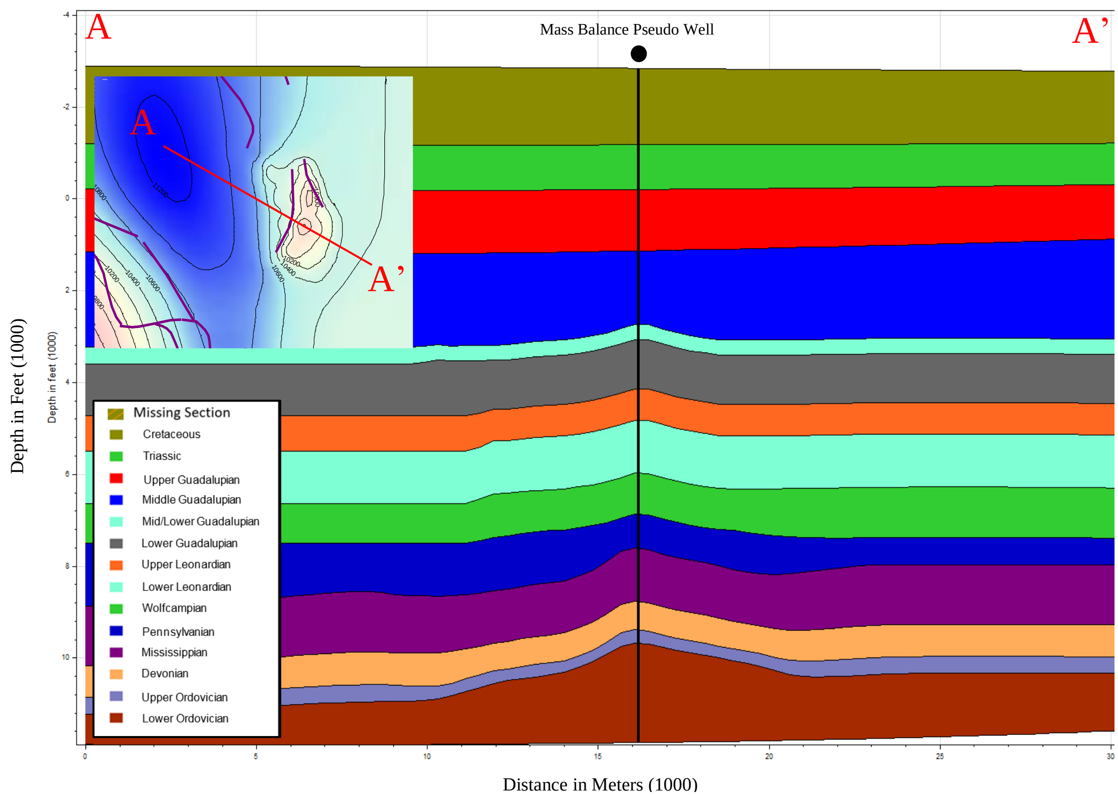

Figure 10. Conformable or "Layer cake" structural trapping surfaces above the Ellenburger Formation and below the San Andreas Formation. Vertical line penetrating anticline apex represents the incorporated 1-D model.

surfaces were slightly altered and smoothed in the areas where the maps are directly merged. To verify the smoothing operations would have little effect on the amount and type of generated hydrocarbons, the workflow used in this analysis (discussed in more detail later) was executed independently using the original and smoothed structure maps. When the output of the two models were compared, it was determined that the smoothing operations had little effect on the quality and quantity of modeled hydrocarbon generation maps.

Decades of work has been conducted to better understand hydrocarbon generation. The complexity of these processes is apparent, therefore simplified generative models and correlations are used in this analysis. In 1995, Andrew Pepper and Peter Corvi outlined some of the fundamental components used when modeling hydrocarbon generation. Their models related first order reaction kinetics and the Arrhenius law: kerogen degradation rate through time (i.e. hydrocarbon generation) is proportional to kerogen concentration at any time (Pepper, 1991; Pepper and Corvi, 1995a; Tissot and Ungerer, 1987). Significantly more complex correlations are used within the model, but in the most basic context, Trinity software used in this analysis relates experimentally derived average activation energies, reaction rates, and frequency factors to kerogen types, temperatures, and pressures to calculate generative hydrocarbon volumes.

Before hydrocarbon generation can be simulated, a kinetic model must be defined for the Simpson source rock. Kinetic models are a customization parameter that are chosen to emulate source rock intervals. The hydrocarbon kinetic model used in each analysis will largely impact the volumes of hydrocarbons retained and expelled from the Simpson source rock. Initially, a model referred to as "ACH4" is used which relates temperatures and pressures to the sorbative capacity of organic matter (Pepper and

Corvi, 1995c). This kinetic model is typically implemented in conventional petroleum systems and provides an efficient delivery of hydrocarbons from source rock intervals into secondary migration pathways. After choosing this model, source rock input values such as kerogen type, initial kerogen density, organic and inorganic porosities, can be customized within the source rock to create the most realistic expulsion model for the Simpson-Ellenburger petroleum system. During this study, the default values listed by Trinity were determined to be geologically reasonable, and thus were not altered. With these parameters defined, the source rock units within the model can now simulate the expulsion of hydrocarbons into the system.

Hydrocarbon migration is one of the most poorly understood processes in a petroleum system. Due to uncertainty and complexity surrounding migration, we use simplified conceptual models to define where and how hydrocarbons move through the model. Conceptually, hydrocarbons preferentially migrate due to buoyancy in the path of least resistance. These hydrocarbons flow through migration pathways that connect the source to the reservoir for a given volume defined by a fetch area and migration pathway thickness. During continuous generation and secondary expulsion of hydrocarbons into migration pathways, buoyancy pressures will increase resulting in hydrocarbons overcoming capillary forces and migrating towards a trap (Hubbert, 1953). As hydrocarbons fill the reservoir they will either generate enough buoyancy pressure to leak through the seal or hydrocarbons will fill the reservoir completely and spill (Berg, 1975).

The area in which expelled hydrocarbon fluids preferentially migrate and accumulate for a given reservoir is defined as a fetch area. Fetch areas are defined for each time step and are directly influenced by the structure of the Midland Basin through time. The structural evolution of the Midland Basin is complex which makes determining the orientation and shape of the fetch area through time challenging. Trinity contains a back-stripping operation that uses the proposed burial history model to determine paleo-fetch areas, but uncertainty is high due to variable surface depth control located outside of the incorporated 3-D imaged Pegasus Field structure. We attempted to execute this operation anyways, but were unsuccessful. The paleo-structure maps made little to no geologic sense, and approximated paleo-fetch areas were unreasonably high. For this reason, we define a constant and unique 262 km^2 fetch area that is determined at the location of the Pegasus Field and its proximity to the paleo-depocenter during the Early Permian (**Figure 11)**. We also assume for modeling purposes that continued large scale structural alteration of the system is relatively low aside from faulting occurring during the late Mississippian. Simply stated, after the structure of the Midland Basin and Pegasus Field are formed, the system is buried, hydrocarbons are generated, and the preserved system is exhumed to present day depths with little to no major structural deformations. Thermal maturity of a source rock is also considered when defining a fetch area. For this analysis, the study area within the Midland Basin is a mature system, therefore immaturity is not considered when determining fetch areas. Although we seek to match present day parameters within the model, some input parameters are dynamic, do not match present day values, and are not constant through time. This is typically

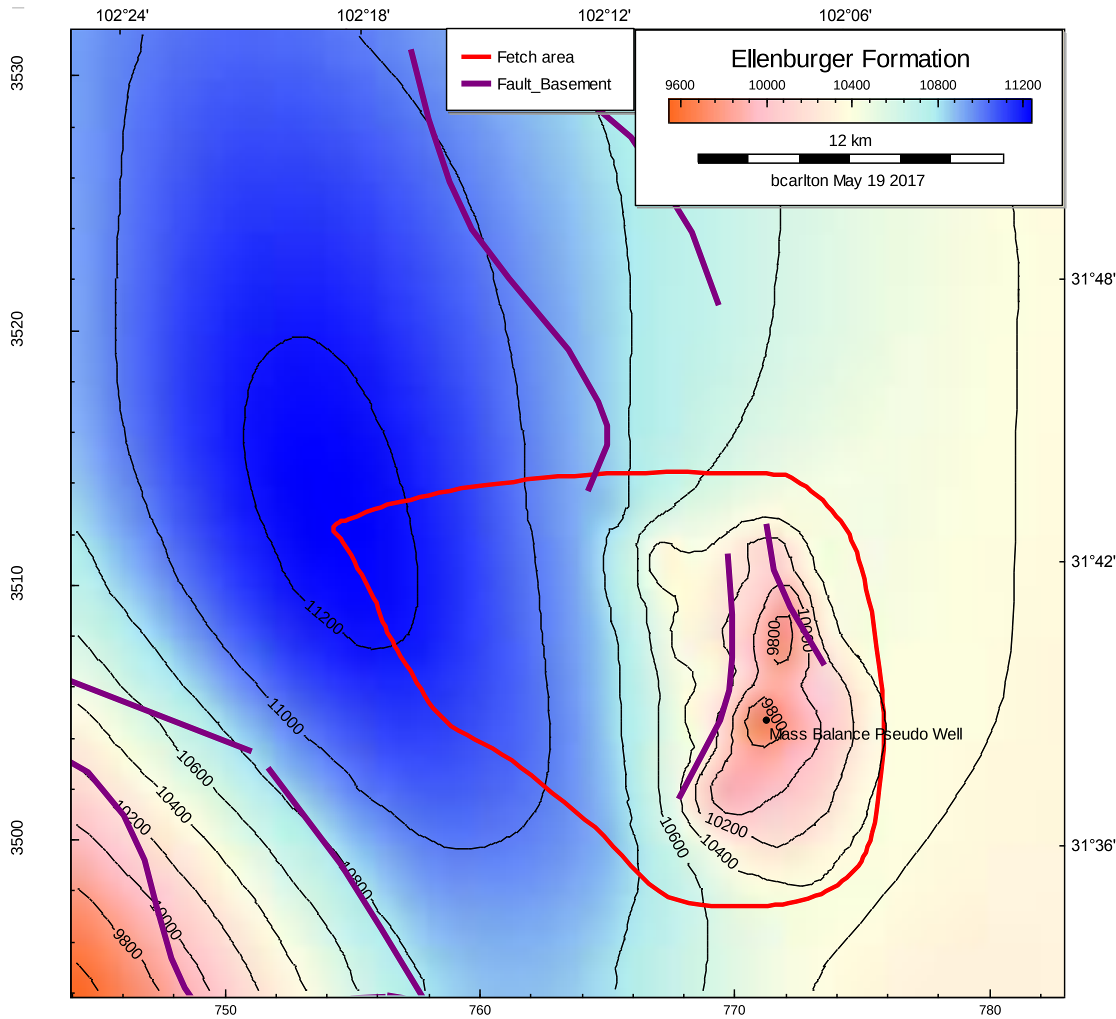

Figure 11. Fetch area for the Pegasus Field Ellenburger trap. Any hydrocarbons generated and expelled from the Simpson Group within the red polygon will charge the Ellenburger trap.

associated with source rock richness values such as Total Organic Content (TOC) and Hydrogen Index (HI). Due to this variation, original richness parameters prior to hydrocarbon generation, referred to as "paleo-parameters", are inferred input parameters. Although these values can be estimated using calculations (Jarvie et al., 2003,2012; Montgomery et al., 2005), original richness values are initially approximated for the

Simpson Group in this study using the following logic: Present day TOC measurements average .5 to 3 wt. % within the Simpson Group (Katz et al., 1994). Discussed in more detail later, most earth scientists agree a minimum of 2 wt. % TOC is needed to generate significant accumulations of producible hydrocarbons (Jarvie, 1991; Peters and Cassa, 1994). With this in mind, reasonable paleo-TOC values must vary from 2 to 4 wt. % assuming 25 to 75 percent of generative carbon is transformed into fluid hydrocarbons to match present day measured TOC data. Although kerogen within the Simpson Group is broadly classified as Type II, the kerogen type found in the Simpson Group is defined using organofacies developed by Andrew Pepper and Peter Corvi in 1995. The Simpson Group is most broadly associated with transgressive maximum flooding systems on depositional margins with kerogens that are dominated by aquatic, algal-derived precursor lipids (Pepper and Corvi, 1995a). This depositional environment and organic input is characteristic of a Type B – Aquatic Marine Clay Rich kerogen. Per these observations, Type B kerogen is used in this study and default parameters such as Gas-Oil Generation Index (GOGI), and Transformation Index (TI), are used to emulate the Simpson Group prior to hydrocarbon generation. Paleo-Hydrogen Index values on the other hand, were derived from modified Van Krevelen diagrams (Tissot and Welte, 1984). Typical immature marine source rocks (Type B) have HI values averaging 500 to 650 mg/gTOC. Trinity defines a HI default input value of 592 mg/gTOC for Type B source rocks within the model, and we determined this value to be a fair approximation for the Simpson source rock. Therefore, an initial TOC input parameter of 2 wt. % and a hydrogen index of 592 mg/g TOC are used in this analysis which both represent reasonable initial source rock richness values (Pepper and Corvi, 1995a).

It is apparent in WTGS's 1949 reservoir characterization that the Ellenburger Formation is a complex reservoir. Facies within the Ellenburger Formation are generally known, but the lateral extent and variation of these facies are difficult to constrain (Kerans, 1988). Because of this observation, we assume in the model a pseudo-effective Ellenburger reservoir interval defined as homogeneous and isotropic throughout the study area. Similar assumptions are applied to Simpson group due to similar spatial variation of rock facies and source rock richness. Under these assumptions, parameters such as lithology, porosity, permeability, etc. are constant and evenly distributed. The Ellenburger reservoir volume is also difficult to quantify due to its oblique shape. With the reservoir boundaries defined in the model, Trinity contains a flash calculator that measures this shape, and can define the overall volume of the Pegasus Field Ellenburger reservoir. We utilize this function to calculate reservoir volumes, but also verify the accuracy by estimating volumes through hand calculations. According to both approaches, maximum resource volumes are approximately 400 MMbbl of undersaturated condensate oil.

Since hydrocarbons in this model are generated during multiple time steps, the distribution of source rock richness values will change through time as the source rock matures. As discussed previously, paleo-maturity maps are generated at each time step using the initial previously defined source rock parameters. As the system matures, solid organics are converted to fluid hydrocarbons. During this process, source rock richness values will correspondingly decrease as hydrocarbons are continuously generated. At the end of each time step (hydrocarbon generation and expulsion event) a set of paleo-maturity maps will estimate the remaining distribution of source rock richness values. These maps now represent the “new” source rock that will be considered for hydrocarbon generation during the following time step. This process is repeated until expulsion ceases.

Little to no maturity data has been documented for the Pegasus Field, therefore indirect measurements were used to best identify thermal maturity in the system. Hydrocarbon fluids produced from the Simpson Group are primarily single phase condensate oils with API Gravities varying from 53 degree API to a max-recorded value found of 59 degree API in a directly adjacent Ellenburger Field at similar depths (**Figure 12**) (Harbison, 1955). This serves as an indirect thermal maturity indicator, and we

CHARACTER OF OIL

	Gravity, A.P.I. @ 60° F.	Sulphur, %
San Andres	29	?
Spraberry	38	0.33
Wolfcamp	42	0.12
Bend	44	0.07
Devonian	48	0.08
Ellenburger	53	0.09

For analyses of Ellenburger oil see:
U. S. Bureau of Mines — Lab. ref. No. 50048
Analyses of Crude Oils from Some West Texas Fields.
R.I. 4959 (1953) — Item 42

Figure 12. API gravity of stacked plays within the Pegasus Field (Harbison, 1955). Reprinted by permission of the WTGS whose permission is required for further use.

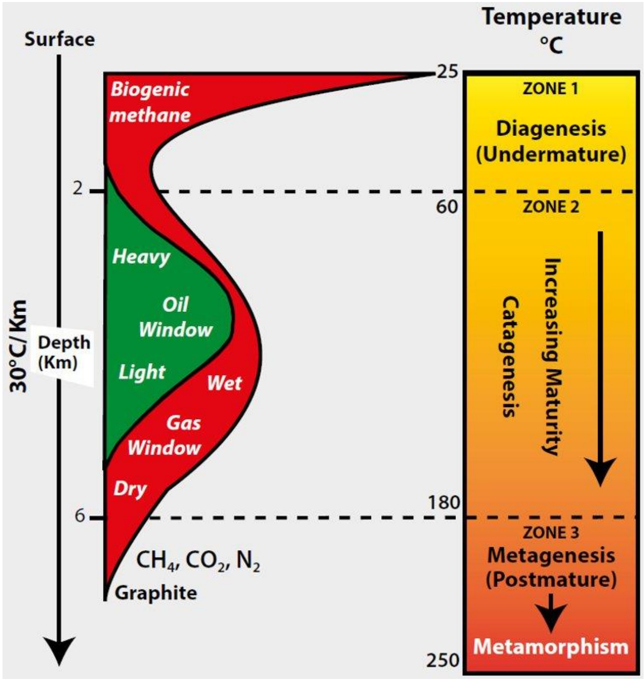

Figure 13. Variation in fluid type with increasing maturity. Modified after Tissot, 1974.

assume source rock intervals must have at least been exposed to temperatures and pressures great enough to generate condensate fluids. Therefore, an effective vitrinite reflectance value (%R_{oEff}) of 1.1 to 1.9 is used to characterize the thermal maturity of the system. As paleo-maturity maps are generated, instantaneous hydrocarbon API gravity distribution maps are also created displaying the variation of oil compositions expelling from the Simpson Group within the fetch area. Long chain hydrocarbons such as heavy oil (~28 API or 887 kg/m^3) are typically generated first and later transition to volatile oils (~40 API or 825 kg/m^3), condensates (~53 API or 743 kg/m^3), and end with wet and dry gas (API gravity N/A) **(Figure 13)**. Gas densities range from wet gas (2.5 kg/m^3) to dry gas (0.71 kg/m^3) at standard temperature and pressure (STP). From these maps, oil API gravities can be associated to the volumes of oil accumulating in the Ellenburger trap. As the Ellenburger reservoir fills, the hydrocarbon volumes from each punctual expulsion event will mix. As the fluids mix, the API gravity within the reservoir is monitored and documented through time until hydrocarbon expulsion ceases.

Tables 1 – 4 define general input parameters used within the model for each petroleum system element. Although many public datasets are available that define parameters for the Simpson-Ellenburger petroleum system, heterogeneity within different lithological units result in a range of measured data values. We acknowledge this variability and use measurements in the model that are geologically reasonable. Produced fluid data and modeling input parameters are represented in **Tables 5 and 6** respectively. All other undefined parameters within the Trinity model are left as default inputs.

Reservoir Characteristics (Ellenburger Fm.)	
Lithology	Dolomite
Year Discovered	3/15/1949
Trap Type	Fault Bounded Anticline
Structure	Anticline
Faulting	2, Normal Faults
Porosity (%)	1-5
Effective Porosity (%)	4
Permeability (mD)	10-1000
Effective Permeability (%)	500
Depth Formation Top (ft.)	12500
Depth Formation Bottom (ft.)	12950
Productive Area (Acres)	12600
Elevation Top (ft.)	9581
Elevation Bottom (ft.)	10410
Structural Relief (ft.)	829
Oil-Water Contact Elevation (ft.)	-10410
Initial Reservoir Pressure (psi)	5760
Average Reservoir Thickness (ft.)	1000
Net Productive (ft.)	250
Net to Gross Ratio (%)	55.6
Reservoir Temperature (Deg. F)	246
Residual Oil Saturation (%)	20
Water Saturation (%)	55
Hydrocarbon Saturation (%)	45
Reservoir Volume (km^3)	8.633
Phase	Single, Condensate Oil
Oil Pressure Gradient (psi)	Calculated
Bubble Point Pressure (psig)	3040-3445

Table 1. Reservoir data for the Ellenburger Formation.

Source Rock Properties (Simpson Fm.)	
Source Rock Classification (Pepper, Corvi, 1995)	B - Aquatic Marine Clay Rich
Kerogen Type	Type II - S
Lithology	Vshale - %50 Interbedded Shale
Modeled Max Maturity (%RoEff)	1.1-1.6
Original Paleo-Total Organic Carbon (%)	1- 4
Original Paleo-TOC (%)	2 - 4
Average Present Day TOC (%)	.5 - 3
Original Paleo-Hydrogen Index (mg/gTOC)	550 - 600
Original Paleo-HI (mg/gTOC)	592
Present Day HI (mg/gTOC)	100 - 150
Shale Volume (%)	50
Thickness (ft.)	400

Table 2. Source rock data for the Simpson Group.

Seal	
Estimated Seal Capillary Pressure (psi)	200
Type	Stratigraphic/Structural
Lithology	Shale

Table 3. Seal data for the Simpson Group.

Migration	
Lithology	Dolomite or Shale
Average Carrier Bed Distance to Trap (km)	13
Average Carrier Bed area (km^2)	120
Average Thickness (km)	0.03048
Residual Hydrocarbon Saturation (%)	20

Table 4. Migration parameters for the Ellenburger Formation.

Ellenburger Production Data	
Number of Wells	120
Average Oil Gravity (Deg API @ 60 Deg F)	53
Oil Density (g/cc)	0.76693
Reported Original GOR (scf/bbl)	1400
Cum Oil (MMbbl)	84.172869
Cum Gas (Bcf)*	350.188924
Calculated Cum Gas from GOR (Bcf)	117.842016600
Cum Water (MMbbl)*	4.188935
*Injected gas and water included	

Table 5. Averaged Ellenburger production data from 1949 - 2016.

Modeling Parameters (Trinity)	
GOGI	0.22
Number of Grid Cells	11211
Grid Cell Dimensions (m)	500 x 500
Fetch Area (km^2)	245-275
Gas Sorption Model Used	ACH4 or ARCO
Temperature Gradient (Deg F/ft.)	0.014
Pressure Gradient (psi/ft.)	0.445
TI (mg/g)	18
Average Surface Temperature (Deg F)	65
Average Surface Pressure (psi)	14.69
Total Charged Oil (MMbbl)	Calculated
Total Charged Gas (Bcf)	Calculated
Modeled TMax (Deg. F)	360
Hydrocarbon Migration loss (MMbbl/km^2/100m)	2
Modeled Buoyancy Pressure (psi)	160 - 170

Table 6. Miscellaneous modeling parameters incorporated into Trinity model.

4. METHODOLOGY

4.1. WORKFLOW

Within the Trinity software package used in this research there is currently no pre-defined workflow for completing a mass balance analysis. However, using the aforementioned modeling parameters, algorithms, and kinetics, we proposed and executed the following workflow.

(1) Prior to hypothesis testing, data from **Tables 1-6** and a complete 1-D model including stratal assemblages of 3-D structural surfaces are incorporated into Zetaware Trinity T3© Basin Modeling Software (2016). Thermal maturity calibrations are conducted and established prior to hypothesis testing. (2) Time step subdivisions are then established from the burial history model. The first time step (T=1) begins prior to the critical moment, with each subsequent time step following every 10 million years. Time steps conclude when expulsion ceases.

(3) Using Trinity, a paleo-fetch area is defined for the Pegasus Field Ellenburger 3-D surface (**Figure 11**). (4) With the paleo-Simpson source rock chosen, a paleo-maturity hydrocarbon generation simulation is run for time step 1 resulting in oil (MMbbl) or gas (Bcf) expelled, oil (MMbbl) and gas (Bcf) retained, instantaneous oil API gravity, transformation ratio (TR), remaining paleo-HI (mg/g TOC) and paleo-TOC value (wt. %) maps (**Appendix**). (5) With expelled hydrocarbons present within the petroleum system, charge volumes are documented for migration pathways and reservoir

accumulations. Hydrocarbon volumes and the respective oil gravity that migrate successfully into the Ellenburger trap are documented for the expulsion event. (6) The instantaneous fluid API gravity within the reservoir is recorded at the end of time step 1.

During generation and expulsion, a portion of source rock richness values have been exhausted, therefore a “new” source rock is created that reflects the remaining source rock richness at the end of time step 1. (7) Remaining paleo-hydrogen index (mg/g TOC) and paleo-TOC (wt. %) maps generated at the end of time step 1 are used for the following time step. (8) Steps four through eight are repeated for each subsequent time step until the source rock is exhausted. (9) Final Pegasus Field mixed fluid volume and API gravity are documented.

Simulated hydrocarbon masses are calculated with final petroleum system volumes in place using volume-density conversions. (10) The following hydrocarbon masses are determined: mass oil and gas stored in reservoir (kg); mass oil and gas retained in source rock (kg); mass oil or gas spilled or leaked from reservoir (kg); and mass oil and gas lost during migration (kg). (11) With hydrocarbon masses calculated, final modeled fluid volumes and densities are compared to measured (produced) fluid data. (12) Iterations of steps one through twelve are conducted. (13) Final learnings and key observations from testing are documented. (14) After multiple iterations are completed, steps one through fourteen are repeated for each remaining experimental hypothesis. (15) Finally, after all testing is completed, all hypotheses are evaluated against present day observed datasets and key experimental observations to determine if hypotheses are probable, possible, improbable, or impossible. The following sections identify variations in workflow execution and assumptions for each individual hypothesis.

4.2. WORKING HYPOTHESIS 1

Premise: *The Pegasus Ellenburger Formation was charged by episodic vertical expulsion (-Z) of hydrocarbons from the Simpson source rock, which resulted in up-dip secondary migration within Ellenburger migration pathways towards the Pegasus Field. These accumulations ultimately result in observed present day quality and quantity of hydrocarbon fluids in the Pegasus Field Ellenburger trap.*

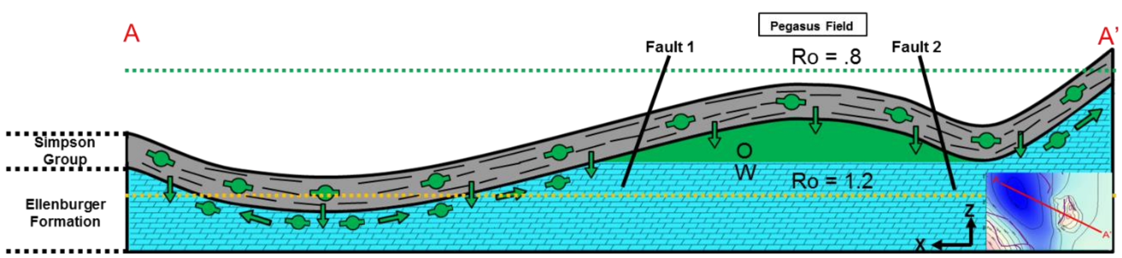

Figure 14. Downward vertical expulsion, migration, and charge conceptual model.

Working Hypothesis 1 represents the first end member possibility of how the Pegasus Field was charged. During testing of Working Hypothesis 1, there are no significant changes to the workflow methodology defined in Section 4.1. Hydrocarbons generated from the Simpson Group expel downward into Ellenburger migration pathways and migrate directly into the Pegasus Field trap except for hydrocarbon volumes lost during migration (**Figure 14**). As a software limitation, we assume mixing of hydrocarbon fluids within the trap and migration pathways are instantaneous and evenly distributed during each charging event. Normal faults within the Ellenburger trap are assumed to be sealing preventing upward leakage through time. If the Pegasus Field becomes completely filled with hydrocarbons, we assume all following expelled volumes mix within the reservoir, but are immediately leaked or spilled. A source rock TOC value of 2 weight percent, a HI value of 592 mg/g TOC, and the ACH4 kinetic model are used during testing of Working Hypothesis 1. Hydrostatic pressure conditions are assumed within the entire system, and buoyancy is the main driver of hydrocarbon fluid flow. All petroleum system rock intervals are homogeneous and isotropic using petroleum system properties found in **Tables 1 – 6**.

4.3. WORKING HYPOTHESIS 2

Premise: *The Pegasus Ellenburger Formation was charged by hydrocarbons that migrated laterally through intraformational (horizontal) flow paths within the Simpson source rock towards areas of accumulation during periods of episodic expulsion. These accumulations ultimately resulted in present day observed quality and quantity of hydrocarbon fluids in the Pegasus Ellenburger Trap. No vertical hydrocarbon expulsion (-Z) is considered.*

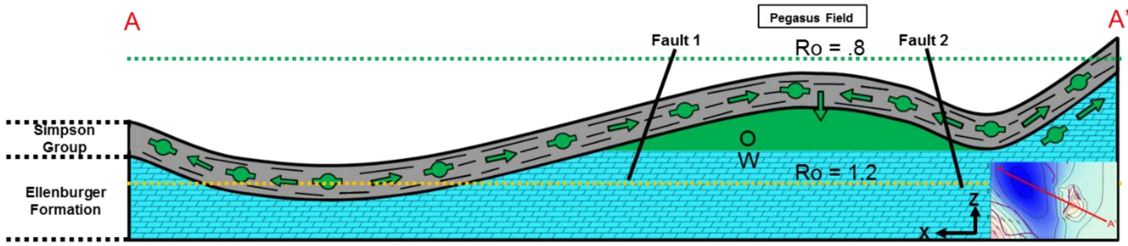

Figure 15. Horizontal intraformational expulsion, migration, and charge conceptual model.

Working Hypothesis 2 was chosen because it represents another possible model for how hydrocarbons charged the Pegasus Field. Previously in Working Hypothesis 1, low API gravity oils were expelled into migration paths where they are retained as residual volumes and never reach the Pegasus trap. For Working Hypothesis 2, generated hydrocarbons are contained within the Simpson Group which provides direct secondary migration of hydrocarbons into the Pegasus Field. We assume hydrocarbon fluids only migrate laterally throughout the Simpson source rock within thin permeable rock units that are saturated with hydrocarbons (**Figure 15)**.

Similar to the previous hypothesis, intra-reservoir mixing is instantaneous and homogeneous within the trap. Simpson units within the Pegasus Field are assumed to have a capillary sealing pressure greater than or equal to the magnitude of accumulated in-reservoir buoyancy pressure. All migration occurs within the source rock, therefore no hydrocarbons enter Ellenburger migration pathways found in the fetch area. Similarly, if the Pegasus Field trap becomes completely filled with hydrocarbons, we assume all following expelled volumes mix within the reservoir but are immediately leaked or spilled. Working Hypothesis 2 will also test the workflow for using a source rock with 2 weight percent TOC, a HI value of 592 mg/g TOC, and the ACH4 expulsion model. All petroleum system rock intervals are homogeneous and isotropic using petroleum system properties found in **Tables 1 – 6**.

4.4. WORKING HYPOTHESIS 3

Premise: *Doubling TOC source rock richness values will result in a positive correlation between modeled and observed hydrocarbon fluid values (quality and quantity) in the Pegasus Ellenburger Trap.*

Speculation regarding minimum TOC richness values needed for a source rock to generate sufficient hydrocarbon volumes to charge a petroleum system are continuously debated. Variation of this parameter within the model is tested for each time step to better understand how this variable impacts generated hydrocarbon volumes. Horizontal intraformational expulsion is assumed during testing with assumptions similar to Working Hypothesis 2. TOC values are doubled to 4 weight percent while HI values remain unchanged at 592 mg/g TOC. Similar to before, if the Pegasus Field trap becomes completely filled with hydrocarbons, we assume all following expelled volumes mix within the reservoir but are immediately leaked or spilled. All petroleum system rock intervals are homogeneous and isotropic using petroleum system properties found in **Tables 1 – 6** and assumptions listed in Section 4.2.

4.5. WORKING HYPOTHESIS 4

Premise: *Altering the source rock kinetic model will result in more retained hydrocarbons, thus providing a better representation of unconventional petroleum systems. The new kinetic model will result in a positive correlation between modeled and observed hydrocarbon fluid values (quality and quantity) in the Pegasus Ellenburger Trap.*

As the focus of hydrocarbon exploration transitions from conventional to unconventional reservoirs, the need to quantify previously unknown unconventional resource volumes is imperative. Traditional basin models focused more towards conventional type plays where modeled source rocks expel almost all of the hydrocarbons into conventional traps with minimal retained volumes. A discrepancy arose when the industry realized a larger remaining hydrocarbon potential is present within source rocks, loosely described here as unconventional plays. Previous testing of Working Hypotheses 1 – 3 primarily focused on the quality and quantity of hydrocarbon fluids found only within conventional reservoirs. In an attempt to make the model more robust, we now seek to modify the kinetic model to determine if larger retained unconventional volumes can be modeled while still matching the quality and quantity of hydrocarbon fluids found within the Ellenburger Formation. The previously used ACH4 expulsion model does not account for organic porosity nor hydrocarbon saturation within this porosity. Due to this limitation, retained volumes are underestimated using this kinetic model.

This Working Hypothesis considers that the sorbative capacity of shales, due to hydrocarbons either absorbing or adsorbing to clay minerals and kerogen, have a significant impact on retained source rock hydrocarbon volumes (Ambrose et. al, 2011). To best represent this geologic process, the ARCO kinetic model is used instead of the ACH4 model. The ARCO model accounts for both saturations in organic and inorganic porosity which will impact the amount of retained hydrocarbons within the model (Gong and Rodrigquez, 2017). Similar to Working Hypothesis 3, we assume horizontal intraformational migration is the most appropriate migration model to identify how fluids are moving though the system. Again, if the Pegasus Field trap becomes completely filled with hydrocarbons, we assume all following expelled volumes mix within the reservoir but are immediately leaked or spilled. Initial source rock richness parameters are a 4 weight percent TOC and a HI value of 592 mg/g TOC. Again, all petroleum system rock intervals are homogeneous and isotropic using petroleum system properties found in **Tables 1 – 6** and assumptions listed in section 4.2.

5. RESULTS

Modeled hydrocarbon volume and mass distributions are presented in **Table 7** for all hypotheses considered in this analysis. For the given fetch area, columns two through six represent the total amount of hydrocarbons generated, expelled, and retained within the Simpson Group source rock. Columns seven and eight describe the total amount of hydrocarbons retained within Ellenburger Formation migration pathways which represent residual accumulations throughout the fetch area. Columns nine and ten represent hydrocarbon resource estimates for the Pegasus Field Ellenburger reservoir. Finally, hydrocarbon volumes and masses lost due to the leakage or spilling of hydrocarbons from the Pegasus Field are presented in columns eleven and twelve.

Oil API gravity mixing tables for each working hypothesis are presented in **Tables 8 – 11**. Expelled oil and gas volumes for each time step subdivision represent punctual charge events of hydrocarbons entering the Pegasus Field trap. Incremental changes in cumulative oil densities are documented and presented as the Ellenburger trap continuously fills. Final cumulative Ellenburger Pegasus Field API gravities for Working Hypothesis 1 - 4 are 54.3, 54.5, 51.2, and 49.0 respectively.

	Source Rock Volumes						Migration Volumes		Reservoir Volumes		Lost Volumes	
	I	II	III	IV	V	VI	VII	VIII	IX	X	XI	XII
	Total Simpson Gp. Oil Volume Generated (MMbbl)	Total Simpson Gp. Gas Volume Generated (Bcf)	Total Simpson Gp. Oil Volume Expelled (MMbbl)	Total Simpson Gp. Gas Volume Expelled (Bcf)	Total Oil Volume Retained In Simpson Gp. Source Rock (MMbbl)	Total Gas Volume Retained In Simpson Gp. Source Rock (Bcf)	Total Residual Oil Volume In Migration Pathway (MMbbl)	Total Residual Gas Volume In Migration Pathway (Bcf)	Total Trapped Oil Volume In Pegasus Ellenburger Fm. (MMbbl)	Total Trapped Gas Volume In Pegasus Ellenburger Fm. (Bcf)	Total Leaked/Spilled Oil Volumes From Pegasus Ellenburger Fm. (MMbbl)	Total Leaked/Spilled Gas Volumes From Pegasus Ellenburger Fm. (Bcf)
Working Hypothesis 1	3,054.0	2,237.0	2,792.0	1,870.0	262.0	367.0	230.00	322.00	400.0	698.8	2,162.0	849.2
Working Hypothesis 2	3,054.0	2,237.0	2,792.0	1,870.0	262.0	367.0	0.0	0.0	400.0	698.8	2,392.0	1,171.2
Working Hypothesis 3	4,642.0	4,398.6	4,190.0	3,665.0	452.0	733.6	0.0	0.0	400.0	698.8	3,790.0	2,751.2
Working Hypothesis 4	2,543.0	11,926.0	1,919.0	600.0	624.0	11,326.0	0.0	0.0	400.0	570.4	1,519.0	29.6

	Source Rock Mass						Migration Mass		Reservoir Mass		Lost Mass	
	I	II	III	IV	V	VI	VII	VIII	IX	X	XI	XII
	Total Simpson Gp. Oil Mass Generated (Kg)	Total Simpson Gp. Gas Mass Generated (Kg)	Total Simpson Gp. Oil Mass Expelled (Kg)	Total Simpson Gp. Gas Mass Expelled (Kg)	Total Oil Mass Retained In Simpson Gp. Source Rock (Kg)	Total Gas Mass Retained In Simpson Gp. Source Rock (Kg)	Total Residual Oil Mass In Migration Pathway (Kg)	Total Residual Gas Mass In Migration Pathway (Kg)	Total Trapped Oil Mass In Pegasus Ellenburger Fm. (Kg)	Total Trapped Gas Mass In Pegasus Ellenburger Fm. (Kg)	Total Leaked/Spilled Oil Mass From Pegasus Ellenburger Fm. (Kg)	Total Leaked/Spilled Gas Mass From Pegasus Ellenburger Fm. (Kg)
Working Hypothesis 1	3.69E+11	7.98E+10	3.55E+11	6.67E+10	3.14E+10	7.38E+09	2.80E+10	1.15E+10	4.85E+10	2.49E+10	2.69E+11	3.03E+10
Working Hypothesis 2	3.69E+11	7.98E+10	3.55E+11	6.67E+10	3.14E+10	7.38E+09	0.00E+00	0.00E+00	4.85E+10	2.49E+10	2.98E+11	4.18E+10
Working Hypothesis 3	5.61E+11	1.57E+11	5.33E+11	1.31E+11	5.43E+10	1.47E+10	0.00E+00	0.00E+00	4.93E+10	2.49E+10	4.67E+11	9.82E+10
Working Hypothesis 4	3.07E+11	4.26E+11	2.44E+11	2.14E+10	7.49E+10	2.28E+11	0.00E+00	0.00E+00	4.99E+10	2.04E+10	1.89E+11	1.06E+09

Table 7. Hydrocarbon volume and mass distributions for the Simpson-Ellenburger petroleum system.

Year (Ma)	Expelled Oil (MMbbl)	Expelled Gas (Bcf)	Instantaneous GOR (scf/bbl)	Expelled Oil API Gravity (Degree API)	Reservoir Oil API Gravity (Degree API)	Density Oil (Kg/m3)	Density Gas (Kg/m3)
285	54.0	0.0	-	28.0	-	-	-
275	174.0	0.0	-	29.5	-	-	-
265	611.0	0.0	-	32.9	32.9	860.7	-
255	1450.0	916.0	631.7	55.2	49.9	780.0	2.5
245	501.0	954.0	1904.2	58.0	54.3	761.6	1.8
235	0.0	96.0	-	-	54.3	-	0.8
225	0.0	1.0	-	-	54.3	-	0.8
Present Day	-	-	-	-	54.3	-	-
Total Oil Expelled (MMbbl)	2792.0						
Total Gas Expelled (Bcf)	1966.0						

Table 8. Working Hypothesis 1 Pegasus Field hydrocarbon mixing table.

Year (Ma)	Expelled Oil (MMbbl)	Expelled Gas (Bcf)	Instantaneous GOR (scf/bbl)	Expelled Oil API Gravity (Degree API)	Reservoir Oil API Gravity (Degree API)	Density Oil (Kg/m3)	Density Gas (Kg/m3)
285	54.0	0.0	-	28.0	28.0	887.1	-
275	174.0	0.0	-	29.5	29.0	881.6	-
265	611.0	0.0	-	32.9	32.0	865.4	-
255	1450.0	916.0	631.7	55.2	49.9	780.0	2.5
245	501.0	954.0	1904.2	58.0	54.5	760.9	1.8
235	0.0	96.0	-	-	54.5	-	0.8
225	0.0	1.0	-	-	54.5	-	0.8
Present Day	-	-	-	-	54.5	-	-
Total Oil Expelled (MMbbl)	2792.0						
Total Gas Expelled (Bcf)	1966.0						

Table 9. Working Hypothesis 2 Pegasus Field hydrocarbon mixing table.

Year (Ma)	Expelled Oil (MMbbl)	Expelled Gas (Bcf)	Instantaneous GOR (scf/bbl)	Expelled Oil API Gravity (Degree API)	Reservoir Oil API Gravity (Degree API)	Density Oil (Kg/m3)	Density Gas (Kg/m3)
285	90.0	0.0	-	28.0	28.0	887.1	-
275	210.0	0.0	-	29.0	29.5	878.9	-
265	1190.0	0.0	-	33.3	32.5	862.8	-
255	2700.0	1660.0	614.8	54.4	51.2	774.5	2.5
245	0.2	1790.0	8.95E+06	58.0	51.2	774.5	1.3
235	0.0	215.0	-	-	51.2	-	0.8
225	0.0	0.0	-	-	51.2	-	-
Present Day	-	-	-	-	51.2	-	-
Total Oil Expelled (MMbbl)	4190.2						
Total Gas Expelled (Bcf)	3665.0						

Table 10. Working Hypothesis 3 Pegasus Field hydrocarbon mixing table.

Year (Ma)	Expelled Oil (MMbbl)	Expelled Gas (Bcf)	Instantaneous GOR (scf/bbl)	Expelled Oil API Gravity (Degree API)	Reservoir Oil API Gravity (Degree API)	Density Oil (Kg/m3)	Density Gas (Kg/m3)
290	0.0	0.0	-	-	0.0	1076.0	-
280	0.0	0.0	-	-	0.0	1076.0	-
270	531.0	70.0	131.8	36.0	36.0	844.8	2.5
260	1040.0	188.0	180.8	43.8	41.6	817.4	1.3
250	348.0	342.0	982.8	58.3	49.0	783.9	0.8
240	0.0	0.0	-	-	49.0	-	-
230	-	-	-	-	49.0	-	-
Present Day					49.0	-	-
Total Oil Expelled (MMbbl)	1919.0						
Total Gas Expelled (Bcf)	600.0						

Table 11. Working Hypothesis 4 Pegasus Field hydrocarbon mixing table.

6. DISCUSSION

Mismatches between modeled reservoir accumulations and produced fluids were encountered during hypothesis testing. Although variations were observed, we do not always conclude the model is incorrectly emulating the Pegasus Field petroleum system. Instead, we are more critical of the proposed hypotheses and input parameters. Understanding the limitations of each working hypothesis is crucial for identifying the reasons for any observed discrepancies. In some cases, analysis of these discrepancies led to some of the most crucial learnings from experimentation.

6.1. WORKING HYPOTHESIS 1

During testing of Working Hypothesis 1 we use an approach that is tailored to conventional-style reservoirs where vertical migration is the primary delivery mechanism of hydrocarbons into the reservoir rock. Downward expulsion of hydrocarbon fluids into the Ellenburger Formation is hypothesized and tested to determine if the input parameters and proposed method of migration will result in present day reservoir volumes. Paleo-maturity maps generated for Working Hypothesis 1 can be found in the **Appendix**. These maps are used to approximate expelled volumes and the respective API gravity for each expulsion event.

When analyzing expelled hydrocarbon volumes for Working Hypothesis 1, we begin to understand the generative potential of the Simpson Group. **Figure 16** represents the variation of expelled oil and gas volumes during each time step. In year 285 Ma, the first expulsion of hydrocarbons enter the system. These hydrocarbons move vertically downward into the Ellenberger Formation and begin migrating towards the Pegasus trap. As the hydrocarbons are migrating, a portion of the expelled volume is trapped within the migration pathway as a residual hydrocarbon accumulation. Using residual saturation values defined in **Table 4**, we approximate 230 MMbbl of oil can be retained in

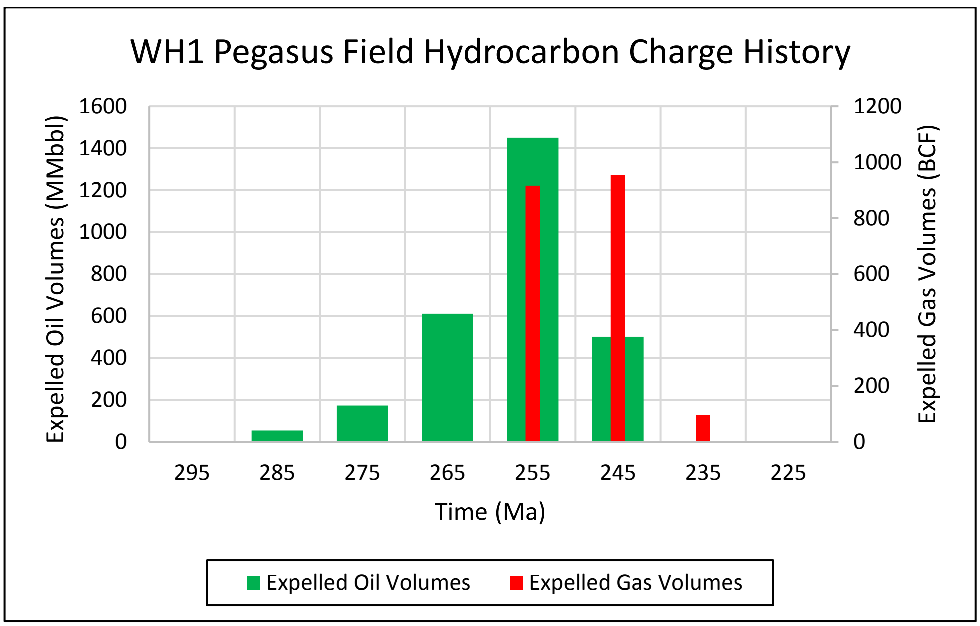

Figure 16. Hydrocarbon charge history for Working Hypothesis 1.

migration pathways as residual hydrocarbons. This accumulation is approximately reached after the second expulsion event at 275 Ma. After this time, expelled hydrocarbons at each subsequent time step migrate directly into the Pegasus trap through preferential flow paths established by residual hydrocarbons.

The critical moment for Working Hypothesis 1 occurs during the third punctual expulsion event at 265 Ma when approximately 611 MMbbl of 33 API gravity oil with no expelled gas volumes migrate into the trap completely filling it resulting in approximately 211 MMbbl of oil leaking or spilling. A maximum expulsion of 1,450 MMbbl of 55.6 API gravity oil occurs during the fourth punctual expulsion event at 255 Ma. At the same time, gas volumes are beginning to expel rapidly as temperatures and pressures continue to rise during burial resulting in 916 Bcf of expelled wet gas. After this event at 245 Ma, a significant decrease in the amount of oil, but a relative increase in the amount of gas changing the Pegasus trap is observed. Soon thereafter, a maximum expulsion of 954 Bcf of wet gas is observed as the Simpson source rock expels a final oil volume of 501 MMbbl of 58 API gravity oil. During the next expulsion event, expelled gas volumes plummet to approximately 96 Bcf of dry gas at 235 Ma and are finally exhausted by 225 Ma. After expulsion ceases a modeled GOR (Gas-Oil-Ratio) of 1,747 scf/bbl is observed within the Ellenburger reservoir, which is relatively high compared to the 1,400 scf/bbl GOR measured during initial production.

Original-oil-in-place (OOIP) estimations suggest a maximum of 400 MMbbl can fill the Pegasus Field Ellenburger trap. Cumulative charge volumes total 611 MMbbl at 265 Ma which is more than enough oil to fill the Pegasus trap. Each expulsion event following this moment will alter the composition of the fluids held within in the reservoir as they flush through the system, and a proportional volume of hydrocarbons will either leak or spill immediately from the structure. **Figure 17** depicts a simplified

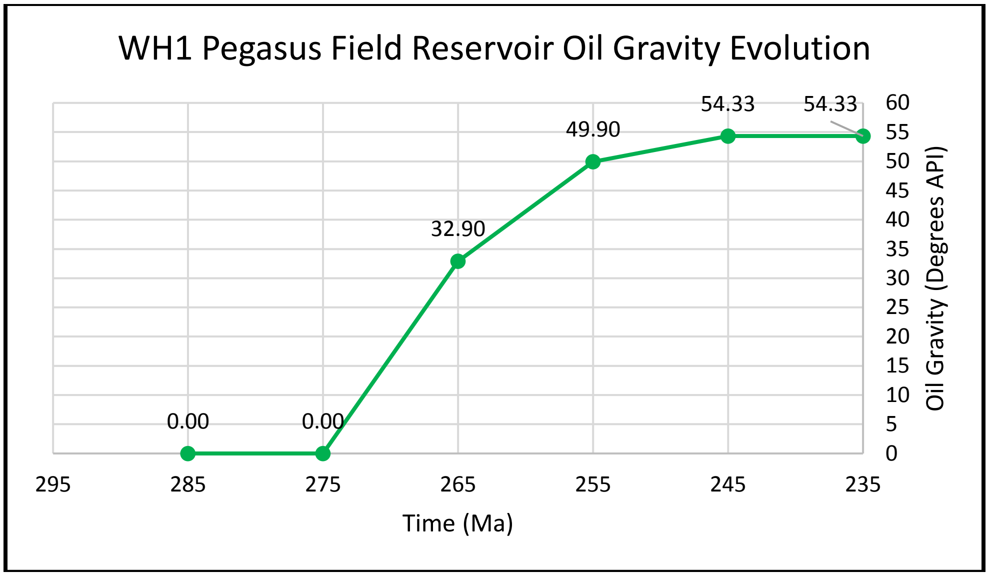

Figure 17. In-reservoir Pegasus Field API gravity evolution for Working Hypothesis 1 during each charge event.

evolution of the resulting average in-reservoir API gravity due to mixing of each expulsion event through time. For the first two expulsion events, no hydrocarbons enter the trap because these hydrocarbons are lost during migration through the Ellenburger Formation. A final fluid composition of 54.33 degree API oil is achieved which correlates well to the 53 API gravity oils observed at present day.

Over the course of 50 million years, the Simpson source rock cumulatively expels 2,792 MMbbl of oil and 1,870 Bcf of gas with approximately 2,162 MMbbl of this oil spilling or leaking from the reservoir. This equates to approximately 4.22E+11 kg of total expelled hydrocarbons and 2.69E+11 kg of spilled oil. Roughly 262 MMbbl of oil and 367 Bcf of gas or 3.88E+10 kg total hydrocarbons are retained within the fetch area migration pathways at present day. Final modeled TOC distributions at present day range from 1.58 wt.% to 1.64 wt.% within the fetch area with modeled HI values ranging from 10 mg/g TOC to 20 mg/g TOC.

It is important to acknowledge and discuss the limitations of the model when applying the workflow to this working hypothesis. Previously, we assumed all generated hydrocarbons will expel downward directly into the Ellenburger Formation. This is conceptually a poor assumption, because vertical expulsion in the +Z-direction may also have occurred through time. Whether hydrocarbons expel upwards or downwards from the Simpson Group, the sealing capacity between the Simpson Group and overlying Montoya Formation will highly influence expulsion direction (England et. al, 1987; Skerlec, 1999).

As previously discussed, most earth scientists agree a source rock with less than 2 wt. % TOC is not rich enough to generate sufficient amounts of hydrocarbons needed to fill a trap the size of the Pegasus Field (Jarvie, 1991; Peters and Cassa, 1994). Although this low value is use in the model, we initially tested pessimistic richness values to better understand the limitations of the model. Unexpectedly, we were able to generate more than enough hydrocarbons to fill the Pegasus reservoir and provide a fair match for in-reservoir mixed API gravity of oil.

In conclusion we determine Working Hypothesis 1 is confirmed as a possible explanation for how hydrocarbons move through the petroleum system due to a relatively close match between measured data and modeled results.

6.2. WORKING HYPOTHESIS 2

Working Hypothesis 2 represents the second end member possibility for how hydrocarbons expel and migrate towards the Pegasus Field. In Working Hypothesis 1, initial oil volumes were expelled into migration paths where they are retained as

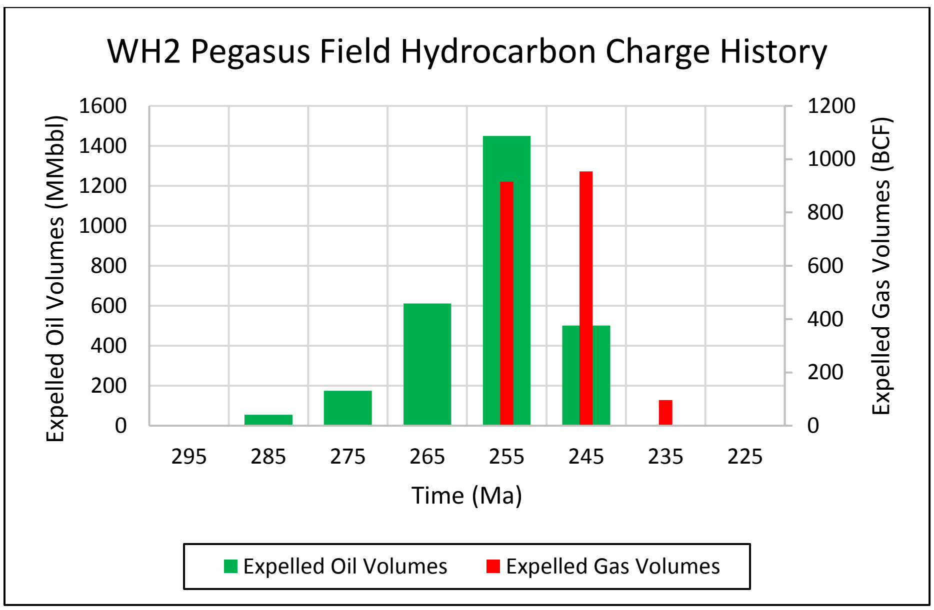

Figure 18. Hydrocarbon charge history for Working Hypothesis 2.

residual volumes that never reach the Pegasus trap. For Working Hypothesis 2, generated hydrocarbons are contained within the Simpson Group which provides direct secondary migration of hydrocarbons into the Pegasus Field trap.

Expelled volumes of oil and gas are approximately the same for Working Hypothesis 1 as well as the final API gravity of oils found in the trap (**Figure 18 and 19**). The primary difference between the two Working Hypotheses is the timing of the critical moment occurs at 285 Ma resulting in heavy 28 API gravity hydrocarbons beginning to fill the Ellenburger Formation**.** Again, peak oil expulsion occurs at 255 Ma and peak gas expulsion occurs ate 245 Ma. Expelled hydrocarbon volumes total 2,792 MMbbl of oil and 1,870 Bcf of gas with approximately 2,392 MMbbl of oil spilling or leaking from the reservoir. This equates to 4.22E+11 kg of total expelled hydrocarbons and 2.98E+11 kg of spilled or leaked oil. Roughly 262 MMbbl of oil and 367 Bcf

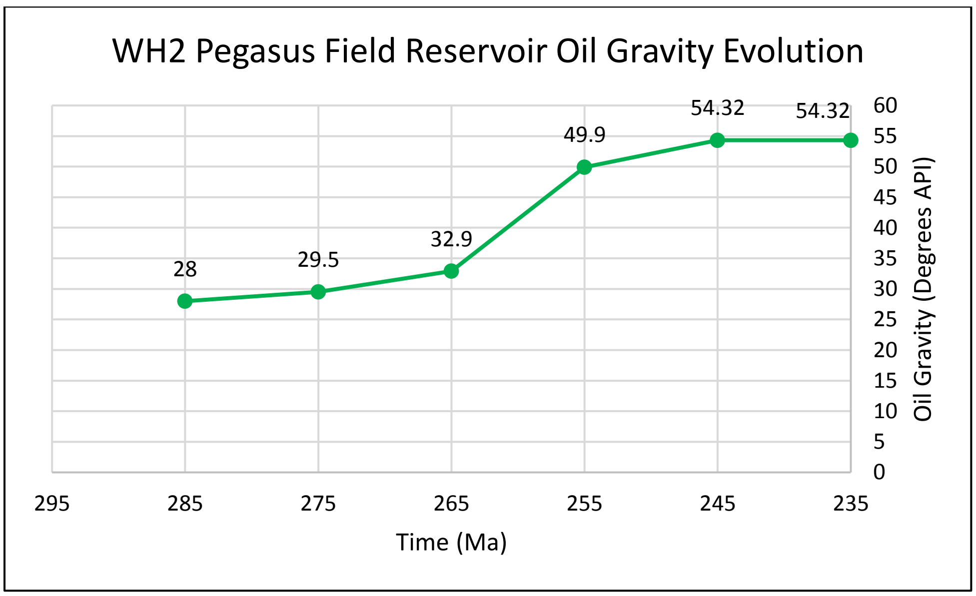

Figure 19. In-reservoir Pegasus Field API gravity evolution for Working Hypothesis 2 during each charge event.

of gas is retained in the Simpson Group equating to a total hydrocarbon mass of 3.88E+10 kg. The final modeled API gravity of trapped oil is 54.32 which is slightly heavier than measured oil gravities. Similar to Working Hypothesis 1, after expulsion ceases a modeled GOR of 1,747 scf/bbl is observed within the Ellenburger reservoir, which is also relatively high compared to the 1,400 scf/bbl GOR measured during initial production. Modeled TOC distributions at present day range from 1.58 wt.% to 1.64 wt.% within the fetch area with modeled HI values ranging from 8 mg/g TOC to 14 mg/g TOC.

A very small difference in final hydrocarbon API gravity is observed when comparing Working Hypotheses 1 and 2. This is most likely due to heavy residual hydrocarbon volumes excluded from mixing during testing of Working Hypothesis 1. It is apparent that residual hydrocarbon accumulations in migration pathways accounted for in Working Hypothesis 1 (230 MMbbl), are too small to create any major variation of API for the two expulsion models. Oversimplified assumptions of Working Hypotheses 1 and 2 may also be too broad to understand how migration paths affect fluids in this model. Structural surfaces generated with greater data density may indicate potential trap areas which will allow more fluids to be retained in migration pathways, thus resulting in a larger variation in oil densities. Homogeneous and isotropic intervals may also be too general of an assumption to characterize the petroleum system. For instance, abundant facies variation throughout the Simpson and Ellenburger Formations may provide stratigraphic traps for hydrocarbon accumulations migrating through carrier beds which will impact the volume and API gravity of hydrocarbon fluids moving towards the Pegasus Field. Rock facies heterogeneities may also cause irreducible oil saturations or free hydrocarbon saturations to be larger than previously thought which will result in more hydrocarbons retained in migration pathways.

Unfortunately, it is challenging to determine if hydrocarbons migrating intraformationally within the Simpson Group expel directly into the structure. At any point along the flow path, hydrocarbons may be deflected outside of the source to a new migration pathway possibly due to a nearby lower pressure zone or any baffle within the source rock. Deflection of hydrocarbons possibly due to facies variation or an unaccounted fault may drive hydrocarbons into overlying formations where they migrate away from the Pegasus reservoir. Also, previously we assumed a residual percentage of hydrocarbons would be retained within migration rock volumes. A more appropriate way to approximate migration loss is to use a defined volume of hydrocarbon migration loss for a given migration fetch area and lithology type. This will allow for more accurate charge volumes in studies where multiple fields are considered. Both migration models tested in Working Hypotheses 1 and 2 provide similar approximations to observed results making it difficult to definitively determine which model is dominant. Further structural analysis of the basin is needed to better understand migration pathways.

Core analyses of the Simpson, Ellenburger, and overlying Montoya formations across the fetch area should be included to this analysis to better identify which migration model is more plausible. We ultimately acknowledge the large uncertainties associated with migration and propose that a combination of both downward vertical and horizontal intraformational migration is the most plausible way of visualizing how hydrocarbons are moving within the fetch area. Repeated testing of this hypothesis with less generalized assumptions may result in a more definitive answer.

In conclusion we determine Working Hypothesis 2 is confirmed as a possible explanation for how hydrocarbons move through the petroleum system due to a relatively close match between measured data and modeled results.

6.3. WORKING HYPOTHESIS 3

After testing migration pathway scenarios, source rock richness values are now altered to gain a better understanding of how variation of the TOC input parameter impacts generated and expelled volumes. TOC is increased to 4 wt.% in order to represent a more rich source rock interval. As previously defined, petroleum system assumptions for Working Hypothesis 3 are similar to those of Working Hypothesis 2.

With intraformational migration of expelled hydrocarbons assumed, the critical moment occurs at 285 Ma when 91 MMbbl of 28 API gravity oil and no gas enters the Pegasus Field Ellenburger trap. Initially, almost double the amount of expelled oil volumes are observed in the first time step compared to first expulsion events from previous tests. At 275 Ma approximately 210 MMbbl of 29 API gravity oil which was then followed by 1,190 MMbbl of 33.3 API gravity oil at 265 Ma with no gas expelled in either expulsion event. This exceptionally large amount of oil floods the system, completely fills the trap, and leaks or spills approximately 790 MMbbl of oil out of the structure. At 255 Ma the maximum oil expulsion event and first appearance of expelled gas into the system occurs. Approximately 2,700 MMbbl of 54.4 API gravity oil and 1,660 Bcf of wet gas expel into the Ellenburger Formation where the hydrocarbons mix and immediately leak or spill. After this event, at 245 Ma, oil expulsion dramatically decreases. A mere 200,000 bbl of 58 API gravity oil coupled with a maximum gas volume of approximately 1,790 Bcf of wet gas is expelled. Finally, HI values

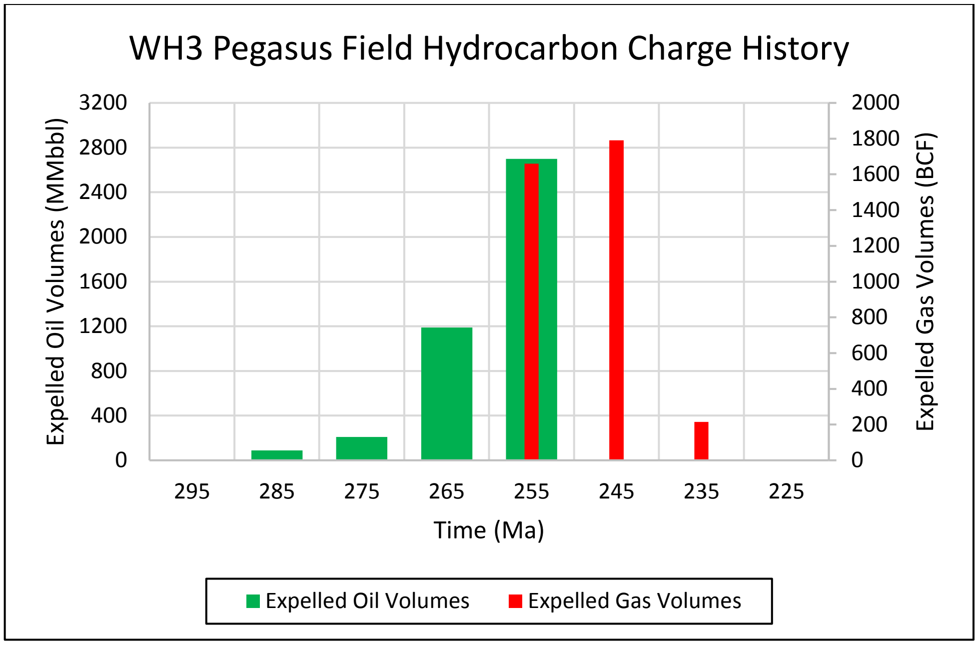

Figure 20. Hydrocarbon charge history for Working Hypothesis 3.

become too small to generate hydrocarbon fluids therefore the Simpson is completely exhausted at 235 Ma after 215 Bcf of dry gas leaves the Simpson Group. Similar to Working Hypotheses 1 and 3, after expulsion ceases a modeled GOR of 1,747 scf/bbl is observed within the Ellenburger reservoir, which is relatively high compared to the 1,400 scf/bbl GOR measured during initial production.

Over the course of 50 million years approximately 4,191 MMbbl of oil and 3,665 Bcf of gas is expelled. With a final API gravity oil of 51.2 observed within the Ellenburger reservoir, approximately 6.64E+11 kg of total hydrocarbons were expelled into the system (**Figure 20 and 21**). Roughly 3,791 MMbbl of oil leaked or spilled from the trap or approximately 5.7 E+11 kg of oil to other up-dip Ellenburger reservoirs.

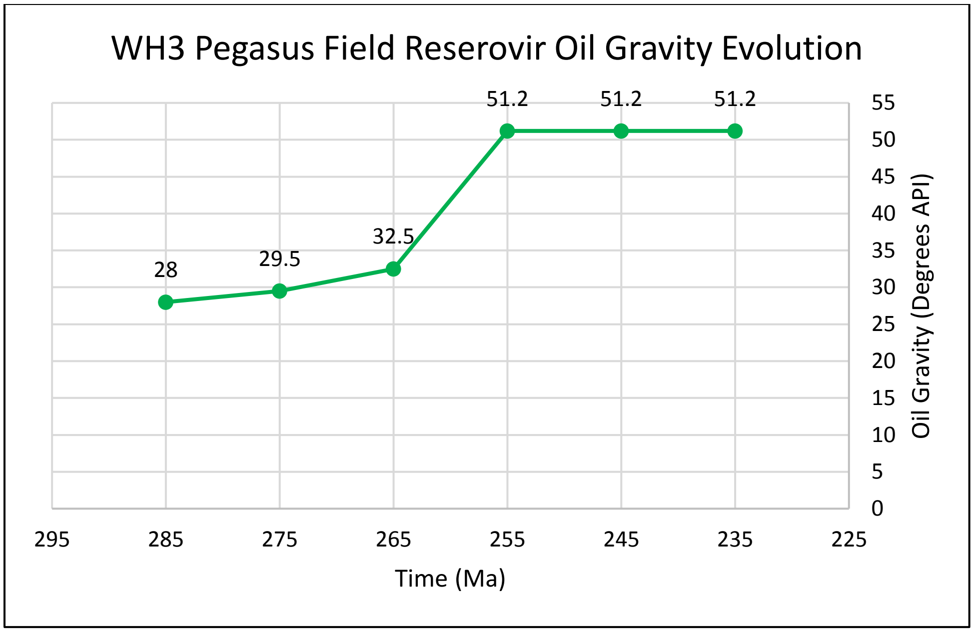

Figure 21. In-reservoir Pegasus Field API gravity evolution for Working Hypothesis 3 during each charge event.

Roughly 452 MMbbl of oil and 733 Bcf of gas is retained in the Simpson Group equating to 6.9E+10 kg of total retained hydrocarbons. Retained hydrocarbon accumulations are roughly double those of Working Hypotheses 1 and 2 which may suggest higher TOC source rocks can retain more hydrocarbons.

Final modeled TOC distributions at present day range from 3.12 wt.% to 3.3 wt.% within the fetch area with modeled HI values ranging from 20 mg/g TOC to 30 mg/g TOC. A final modeled API gravity of 51.2 is observed which is relatively close to present day measured data (**Figure 21)**. The mismatch between observed and modeled fluid densities is relatively small, thus we propose a 4 wt. % TOC richness value provides a fair estimation for modeled in-reservoir oil gravities and more than enough expelled hydrocarbons to fill the Ellenburger trap.

One of the most important observations from testing of Working Hypothesis 3 is we gain a better understanding as to how the model reacts when input richness values are doubled. After testing we observe doubling TOC richness resulted in approximately double the amount of gas and 1.5 times the amount of oil generated and expelled within the fetch area compared to Working Hypothesis 2. With greater amounts of expelled hydrocarbons entering the Ellenburger trap, more hydrocarbons are mixing within the reservoir and leaking or spilling from the structure. We also observe that double the amount of gas and 1.7 times the amount of oil are retained within the source rock. This observation is most likely attributed to the increase in kerogen volumes when TOC values were doubled which will increase the amount of surface area available for hydrocarbon adsorption. These observations have large implications for understanding relative resource potentials between mature plays with source rock intervals of different richness found above and outside the Pegasus Field.

One of the more obvious variations between Working Hypotheses 2 and 3 are oil and gas expulsion rates relative to one another when normalized by volume. According to the charge history of Working Hypothesis 2, a gradual increase in expulsion rates up until maximum expulsion at 255 Ma is observed with a relatively quick decline until expulsion ceases. Oil expulsion rates in **Figure 20** slowly increase to maximum expulsion similar to Working Hypothesis 2, but oil expulsion immediately ceases after 255 Ma. Working Hypothesis 3 expels hydrocarbons much more rapidly than Working Hypothesis 2 which may suggest more rich source rock intervals generate and expel hydrocarbons more rapidly.

Limitations associated with this working hypothesis are similar to those of Working Hypothesis 2 due to the similarities in assumptions and migration method. In conclusion we determine Working Hypothesis 3 is possible due to a fair match between measured data and modeled results.

6.4. WORKING HYPOTHESIS 4

With the shift of industry focus towards unconventional reservoirs, hydrocarbon resources procured directly from source rock intervals has increased dramatically over the past 40 years. After analysis of the first three working hypotheses, a reoccurring theme is apparent: retained hydrocarbon volumes are significantly less when compared to those of expelled volumes. This observation forced us to be more critical of the kinetic model that is being used in the model due to present day exploitation of large and abundant hydrocarbon resources from source rock intervals. Generation kinetics have a direct impact on the amount of expelled and retained hydrocarbon fluid volumes, so variation of this parameter should have a significant impact on fluid volumes and oil gravities. This investigation will determine if the final retained hydrocarbon volumes in previous working hypotheses are realistic. To determine this, the previously used ACH4 kinetic model is switched to the ARCO kinetic model in an effort to better identify unconventional resource potentials. All assumptions and input parameters used in testing of Working Hypothesis 4 are the same as those used in Working Hypothesis 3.

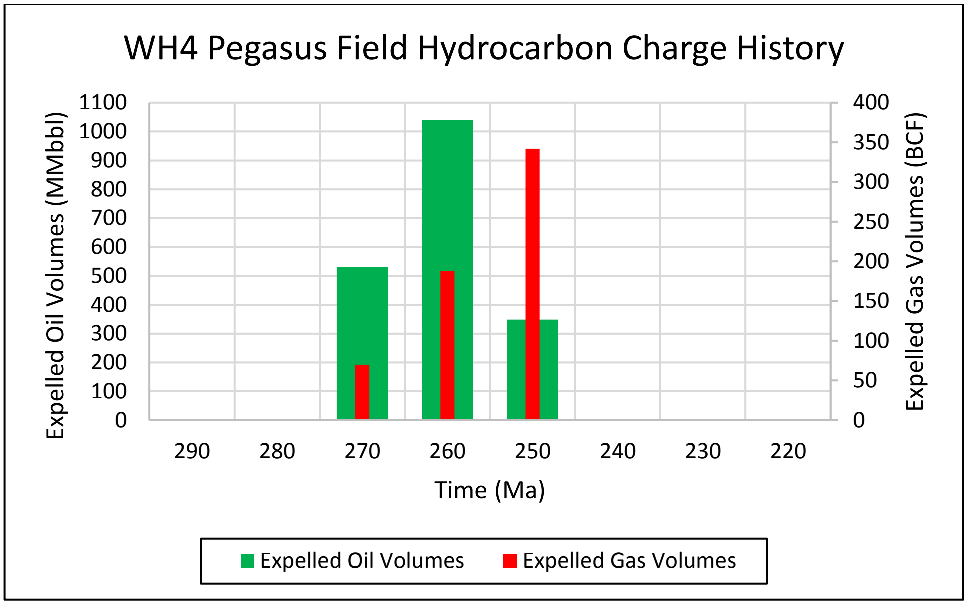

Figure 22. Hydrocarbon charge history for Working Hypothesis 4.

Time steps were altered by 5 Million years to better approximate oil and gas expulsion. The critical moment begins at 270 Ma which is almost 15 million years later than previous working hypotheses. Approximately 531 MMbbl of 36 API gravity oil and 70 Bcf of wet gas are expelled into the Ellenburger trap completely filling the structure and leaking or spilling 131 MMbbl (**Figure 22)**. From this point forward, all excess charge volumes mix and leak or spill directly from the reservoir. Onset of wet gas expulsion is relatively early in the charge history, and initial expelled oil API gravities during time step 1 are relatively higher than previous tests. Ten million years later, the second punctual expulsion event contributes a maximum recorded oil volume of 1,040 MMbbl of 43.85 API gravity oil and 188 Bcf of wet gas. At 250 Ma, oil expulsion drops significantly to only 348 MMbbl of 58 API gravity oil with a 342 Bcf max expulsion volume of dry gas. Expulsion ceases at this point and the source rock is considered to be completely exhausted. After expulsion ceases a modeled GOR of 1,426 scf/bbl is observed within the Ellenburger reservoir, which is a close match compared to the 1,400 scf/bbl GOR measured during initial production.

In total, approximately 1,919 MMbbl of oil and 600 Bcf of gas were expelled into the Ellenburger trap resulting in a final mixed oil of 49.0 degree API equating to a total expelled hydrocarbon mass of 2.65E+11 kg (**Figure 23)**.

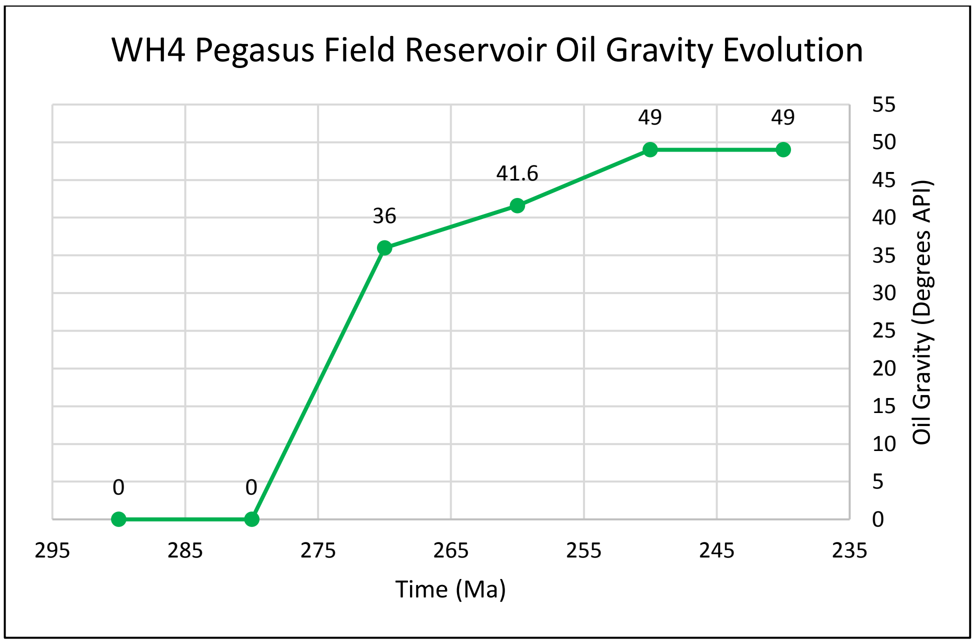

Figure 23. In-reservoir Pegasus Field API gravity evolution for Working Hypothesis 4 during each charge event.

A significant reduction in the amount of expelled gas volumes is observed and is the lowest volume recorded for all working hypotheses. Conversely, retained gas volumes are very large which is attributed to the ARCO expulsion model. Approximately 1,519 MMbbl of oil leaked or spilled from the Pegasus Field Ellenburger Formation equating to 1.89E+11 kg of total hydrocarbons. Roughly 624 MMbbl of oil and 11,326 Bcf of gas is retained in the Simpson Group equating to a maximum observed total hydrocarbon mass of 3.03E+11 kg. Lastly, approximately 1,519 MMbbl of oil and 40 Bcf of gas spilled or leaked from the trap which represents 1.9E+11 kg of total hydrocarbons.

Retained oil volumes are more than double the amount compared to those of Working Hypothesis 3 due to the model accounting for sorbed hydrocarbons within organic and inorganic pores. The shortest expulsion duration is observed during testing of Working Hypothesis 4 resulting in the Simpson source rock being exhausted after only 30 million years. After expulsion ceases, final modeled TOC distributions at present day range from 3.64 wt.% to 3.76 wt.% within the fetch area with modeled HI values ranging from 10 mg/g TOC to 20 mg/g TOC.

Unfortunately, according to DrillingInfo, no hydrocarbons have been produced directly from the Simpson Group in the Pegasus Field, therefore it is not possible to identify if modeled retained hydrocarbon volumes match those at present day. A lack of production data to validate the comparison results in a highly uncertain estimation of retained hydrocarbon volumes. Nonetheless, retained volumes do impact the proportion of expelled volumes, thus significantly affecting the quality and quantity of hydrocarbon fluids entering the Ellenburger trap. As charge volume proportions decrease, final mixed fluid gravities are heavier than those measured at present day.

As expected, variation of generation kinetics largely affected expulsion rates, retained volumes, and hydrocarbon densities in the petroleum system. The ARCO kinetic model significantly reduced the amount of expelled hydrocarbon volumes compared to those of Working Hypothesis 3 where the ACH4 model was used (**Tables 7)**. When comparing total generated hydrocarbons for Working Hypotheses 4 and 3, almost half the amount of oil volumes yet more than double the amount of gas volumes are generated using the ARCO kinetic model. Retained oil volumes were increased by 200 MMbbl and retained gas volumes were increased dramatically with approximately 15 times the amount of gas stored within the 262 km^2 fetch area. Although retained oil volumes were increased, enough oil was expelled from the Simpson Group to fill the Pegasus trap completely. With greater retained hydrocarbon volumes, charge volume proportions were impacted which led to a heavier final modeled API oil gravity. Although the final modeled API oil gravity is relatively low compared to measured data, the modeled reservoir oil is still similar to condensate type oils.

In conclusion we determine Working Hypothesis 4 is possible yet improbable due to a fair match between measured data and modeled results.

6.5. CRITICAL GEOLOGIC PROCESSES

The geologic processes and parameters that have the largest influence on the petroleum system are determined by two different methods: identification during testing of each working hypothesis, and post-testing Monte Carlo simulations. In no particular order, the following critical processes and parameters are defined.

6.5.1. SEAL FORMATION

A competent seal is one of the most vital components of any petroleum system, and is essential for retaining hydrocarbons within a trap. In the Pegasus Field, the Simpson Group is the primary seal that is either leaking or spilling hydrocarbons through time. We initially assume that the Simpson Group forms a uniform and competent seal, thus once the trap is filled to capacity, all excess hydrocarbons spill from the structure instead of leak. Unknowingly, the competent seal assumption resulted in a close match of fluid API gravities and volumes within the Ellenburger trap for each working hypothesis. This observation supports the idea that the Simpson Group acted as a competent seal from the onset of hydrocarbon expulsion to present day. To gain more support for this claim, pressures associated with the seal were explored.

Capillary entry pressures highly impact the quality and capacity of a seal. To better understand these pressures, buoyancy pressure generated from the 829 ft. condensate oil column was back-calculated within the Trinity model and averaged 160 - 170 psi. With the absence of core measurements, it was not possible to approximate capillary displacement pressures (entry pressure) for comparison to modeled buoyancy pressure. Regardless of the precise value of the capillary entry pressure generated by the Simpson group, the capillary pressure must greater than the 160 psi buoyancy pressure to result in present day hydrocarbon accumulations with an 829 ft. oil column (Skerlec, 1999). Similar reasoning is used when evaluating faults that have structurally deformed the basin and the Pegasus Field prior to hydrocarbon generation. Though faults can act as conduits for fluid migration, we propose that the two normal faults found in the trap area are impermeable and restrict fluid movement to overlying reservoirs. We previously assumed all faults were sealing and suggest that the sealing capability of these faults has been constant through time to result in the quality of hydrocarbons found in the trap at present day. Similar to capillary pressures within the seal, fault plane capillary pressures must also be equal to or greater than hydrocarbon buoyancy pressure in order to contain present day accumulations.

Prior to hypothesis testing, we observed an oil-water contact is located at the structural base of the Pegasus Field. This observation supports the idea that most if not all expelled hydrocarbons within the fetch area accumulate, mix, and spill out of the trap. With evidence suggesting hydrocarbons spilled from the trap as opposed to leaked, we gain a better understanding as to where hydrocarbons have accumulated outside of the Pegasus Field. Though we can only speculate these observations, we believe hydrocarbons spilled up-dip towards the eastern shelf and were preferentially diverted away from overlying stacked plays within the Pegasus Field. This may help identify where future undiscovered hydrocarbon accumulations are present, and may explain why high maturity hydrocarbons are located at shallow depths. A biomarker and diamondoid analysis of oils above in stacked plays and oils found on the eastern shelf may provide more information regarding the origins of these fluids.

6.5.2. MIGRATION AND ACCUMULATION

Testing of Working Hypotheses 1 and 2 resulted in two possible models that represent how hydrocarbons are migrating within the system. Again, the primary difference between the models is the residual migration volumes left in the Ellenburger Formation for Working Hypothesis 1. Since hydrocarbons are stranded in the rock, the API gravity of the final accumulation is expected to be variable when comparing both working hypotheses. When the amount of retained hydrocarbons are compared between the Ellenburger Formation, the variation observed was almost negligible, but in petroleum systems where long distance migration is hypothesized, larger accumulations of residual hydrocarbons may have a more significant impact on up-dip fluid compositions (Demaison, 1977; Schowalter, 1979; England, 1987).

Previously we assumed larger hydrocarbons volumes will be stranded within the Ellenburger migration pathways (WH1) compared to those within the Simpson Group (WH2). Unfortunately, this assumption is not always true. We acknowledge that most shale intervals typically have higher critical hydrocarbon saturation potentials compared to dolomitic rock intervals, therefore intraformational migration losses should be larger for Working Hypothesis 2 (Berg, 1975; Schowalter, 1979; England, 1987). Migration losses are not accounted for within the Simpson Group previously in this analysis for two reasons. First, prior to testing we assumed all Simpson Group migration pathways are saturated with hydrocarbons due to hydrocarbon generation. Per this assumption, secondary migration is efficient through interconnected oil stringers, thus little to no hydrocarbons are adsorbed during migration. Second, hydrocarbon migration volumes "lost" within the Simpson Group are accounted for in the retained hydrocarbon volumes when expulsion ceases. For this reason, it appears migration losses are greater within the Ellenburger Formation. Although it is challenging to identify which portion of retained volumes are due to migration losses, we note that migration losses are accounted for during testing of both hypotheses.

It is also important to note that structural surfaces outside of the digitized trap are generalized and represent basin scale structural surfaces, thus folding, faulting, and other field scale structural deformations are not represented. These details may have a large impact on the volumes entering the trap, which in turn would directly impact final fluid densities. Any unaccounted structural deformation may result in hydrocarbons in the fetch area being deflected to overlying structures or stranded within migration pathways. This is certainly a possibility due to the complex structural evolution of the Midland Basin which has resulted in widespread basin scale faulting and highly deformed formations (Hoak, 1988; Horak, 1985). However, even if hydrocarbons migrating up-dip towards the Pegasus Field never reach the trap, we observe volumes generated from the Simpson Group directly above the Ellenburger Formation within the Pegasus Field area are enough to fill the trap completely. If only these charge volumes are considered the final mixed API gravity would average 52 API which is a close representation of measured data.

6.5.3. TIMING OF GEOLOGIC EVENTS

Timing of geologic events, though technically not a geologic process, is perhaps one of the most critical factors that impact the petroleum system. During testing of each hypothesis, timing of events depicted previously by Katz et al. (1994) were revised for this model. This study proposes a range of timing variability for the occurrence of overburden, trap formation, generation, migration, accumulation, preservation, and the critical moment (**Figure 24)**. During hypothesis testing, hydrocarbon generation,

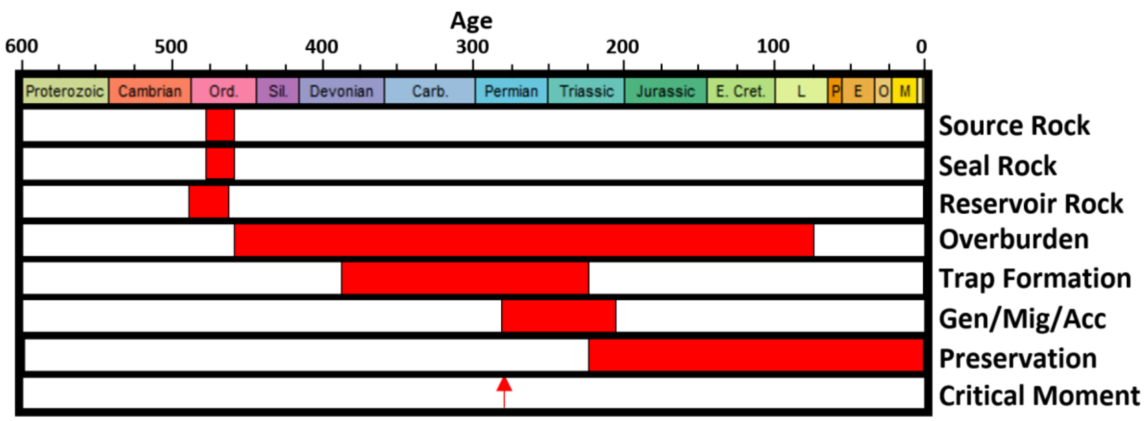

Figure 24. Revised timing of events chart for the Pegasus Field Simpson-Ellenburger petroleum system.

migration, and accumulation occur relatively quickly due to rapid burial and deposition during the Permian. Temperatures and pressures continue to rise within the Pegasus Field past 235 Ma, thus hydrocarbon thermal cracking within the source rock or reservoir may result which can extend the thermal maturation range. It is worth mentioning that secondary in-reservoir thermal alteration (hydrocarbon cracking) is not represented in

Figure 24, nor during hypothesis testing which may potentially extend the time frame interval by 100 million years according to the burial history model.

This study assumes early in the petroleum system model that the anticline structure of the Pegasus Field formed prior to hydrocarbon generation. Uncertainty surrounding this assumption is inherently large knowing that the structural evolution of the Midland Basin is very complex. It is proposed that trap formation, in conjunction with timing of seal competency, varies from the middle to late Devonian (385 Ma) to the last two punctual expulsion events (255 Ma). Although this range is large, we can further constrain the trap timing by examining each punctual expulsion map. For almost every working hypothesis, the last two punctual expulsion events typically expel condensate type fluids and enough barrels to fill the Ellenburger trap completely (**Appendix)**. From this observation we suggest that even if the trap formation was relatively late at approximately 255 Ma, the correct fluid densities and volumes can still be achieved to match present day measurements. This timing is crucial for being able to fill the trap, but also retain the hydrocarbons for preservation.

6.6. CRITICAL PARAMETERS

6.6.1. SOURCE ROCK RICHNESS

As expected, richness input parameters for the Simpson source rock have a direct correlation with the quality, quantity, and duration of hydrocarbon expulsion (Jarvie 2013). As previously discussed, doubling TOC richness values from Working Hypothesis 2 to Working Hypothesis 3 resulted in roughly double the amount of generated, expelled, and retained hydrocarbons. These observations are key when evaluating the relative generation potential of one source rock comparatively to another. If a relatively mature basin is assumed, this realization can be used to reduce uncertainty regarding exploration efforts and ultimately drive business decisions.

Although TOC content of the source rock is an important petroleum system parameter, evidently HI content is equally important when determining expelled volumes. As seen in the **Appendix,** we note two key observations: first, HI values were exhausted much more rapidly than TOC values during each time step and second, the HI value was clearly more of an expulsion limiting factor than TOC due to the larger conversion rate of HI values during the same amount of generation and expulsion time (Jarvie, 2012). The first observation provides a better understanding of how HI values change through time within a source rock. Although the measurements are lab derived, analysis of these values can allow earth scientists to better understand indirect maturity distributions of a basin. HI also provides another tool for maturity analysis along with TOC measurements, provided there is confidence in estimated original paleo-HI values. The second observation is clear during post-testing comparison of TOC and HI maps through time **(Appendix)** with similar observations documented by Jarvie in 2012. Greater than 90% of all HI values were consumed during generation of hydrocarbons, as opposed to TOC maps that indicate roughly 25 - 50% conversion over the course of 40 million years.

6.6.2. THERMAL HISTORY

The thermal history of the Pegasus Field has primary control on the quality of generated hydrocarbon fluids. The constant 45 mW/m^2 basal heat flow and burial of 4,000 ft. of missing section created the environment needed to generate high maturity hydrocarbon fluids. Variation of these parameters may lead to significant mismatches in final mixed fluid densities for each time step. These modeling parameters represent one possibility to match measured hydrocarbon values, but uncertainty is inherently large for this approach. Quite obviously, basal heat flow is not constant nor uniform within a basin and the 4,000 ft. of missing section may represent a geologically unrealistic amount of sediment deposition and subsidence. Theoretically, a basal heat flow curve that varies through time and spatially across the basin, coupled with a smaller amount of missing section or hiatus event may generate similar results that are more geologically reasonable.

6.6.3. GENERATION KINETICS

As discussed previously, ACH4 and ARCO generation kinetics have a large impact on the quality and quantity of expelled hydrocarbon fluids. To identify whether the kinetic models are realistically emulating the Simpson-Ellenburger petroleum system, the computational intricacies and experimental results of each model must be assessed. Unfortunately, the algorithms that define each model are not presented clearly within Trinity, which make an internal comparison challenging. Alternatively, experimental results provide more insight. The ACH4 model (Working Hypotheses 1 – 3) provides a reasonably close approximation to the API gravity of oil produced at present day. The ARCO model (Working Hypothesis 4) on the other hand provides a fair comparison, but is not nearly as precise as the ACH4 model.

Although modeled reservoir API gravities provide a moderately close approximation to produced fluids, we question whether the kinetic models are underestimating or overestimating generated hydrocarbon volumes. Uncertainty surrounding modeled volumes is large, and it is difficult to justify whether the volumes are overestimated or underestimated with only Ellenburger production data available for this analysis. Fortunately, both models provide enough fluid volumes to charge the Pegasus Field which is another critical component to emulate the petroleum system.

6.6.4. FETCH AREA

The fetch area for the Pegasus Field is a critical parameter for estimating hydrocarbon charge volumes. Depending on the areal extent, charge volumes can be significantly affected, thus directly influencing final in-reservoir fluid densities. Prior to testing we assumed a constant fetch area for the Pegasus Field. As previously mentioned, the complex structural evolution of the Midland Basin undoubtedly resulted in variation of this area because the basin was highly deformed during compression and relaxation events. We recognize a constant fetch area is a poor assumption, but also acknowledge that such a simplification was necessary to constrain a parameter that has a large amount of uncertainty associated with it. Due to the complex structural evolution of the basin, much larger or smaller fetch areas are possible which will impact final mixed fluid API gravities. With this in mind, more detailed regional surfaces may allow for better fetch area approximation using the back-stripping method.

6.7. SENSITIVITY ANALYSIS

Monte Carlo simulations are a stochastic computerized approach used to complete a sensitivity analysis which can ultimately generate variable correlations and calibrate models (Hantschel and Kauerauf, 2009). These simulations quantify risk, uncertainty, or project variability for a given set of variables and are useful when trying to understand how the variation of input parameters impact modeled results. Monte Carlo simulations typically follow a generalized workflow which is outlined as follows: prior to executing the simulation, a range of possible values (P10, P50, and P90) are assigned to a distribution of independent variables including TOC, HI, fetch area, source rock thickness, percent of oil and gas leaked or spilled, geothermal gradient, timing of trap, source rock kinetics, and the depth of the source rock through time (**Appendix**). These distributions represent reasonable model input values typically observed within the petroleum system and are either normal, log normal, or triangularly distributed. A set of random numbers according to the distributions is drawn, and a simulation run is performed to calculate hydrocarbon charge volumes. A range of possible outcomes and the frequency that each outcome occurs is calculated randomly over 2,000 iterations. The results of the analysis are then plotted in two separate manners for interpretation: Charge volume frequency distributions and hydrocarbon tornado charge diagrams.

Oil and gas charge volume distributions and their frequency of occurrence during simulation are depicted in **Figure 25**. Average oil charge volumes are approximately 3 billion barrels (Bbbl) with a wide distribution of possible gas charge volumes. **Figure 26** represents ranges of possible oil charge volumes for the Ellenburger Formation and the relative degree of sensitivity for all input parameters. Oil charge volumes range from a minimum of approximately 3 Bbbl to a maximum of approximately 10 Bbbl. TOC richness is determined to be the most sensitive parameter affecting generative oil volumes within the Mont Carlo simulation. The average fetch area during charge events, depth achieved by the source rock interval, thermal gradient, original HI values, and the overall source rock thickness are also important parameters that that have a relatively large influence on oil charge volumes. Due to previously defined assumptions, the timing of trap, source kinetics, amount of oil or gas loss, are constrained and do not have a large impact on charge volumes according to the simulation. Note, source kinetics referred to in the simulation represent hydrocarbon generation temperatures derived from the burial history, not the ARCO or ACH4 models used during testing. Thermal gradient on the other hand, represents variability of the temperature gradient incorporated from the 1-D calibration model.

Gas charge volumes range from a minimum of approximately 1.6 Trillion cubic feet (Tcf) to a maximum of approximately 13 Tcf (**Figure 27**). According to **Figure 27,** the source depth and geothermal gradient are the most sensitive factors affecting

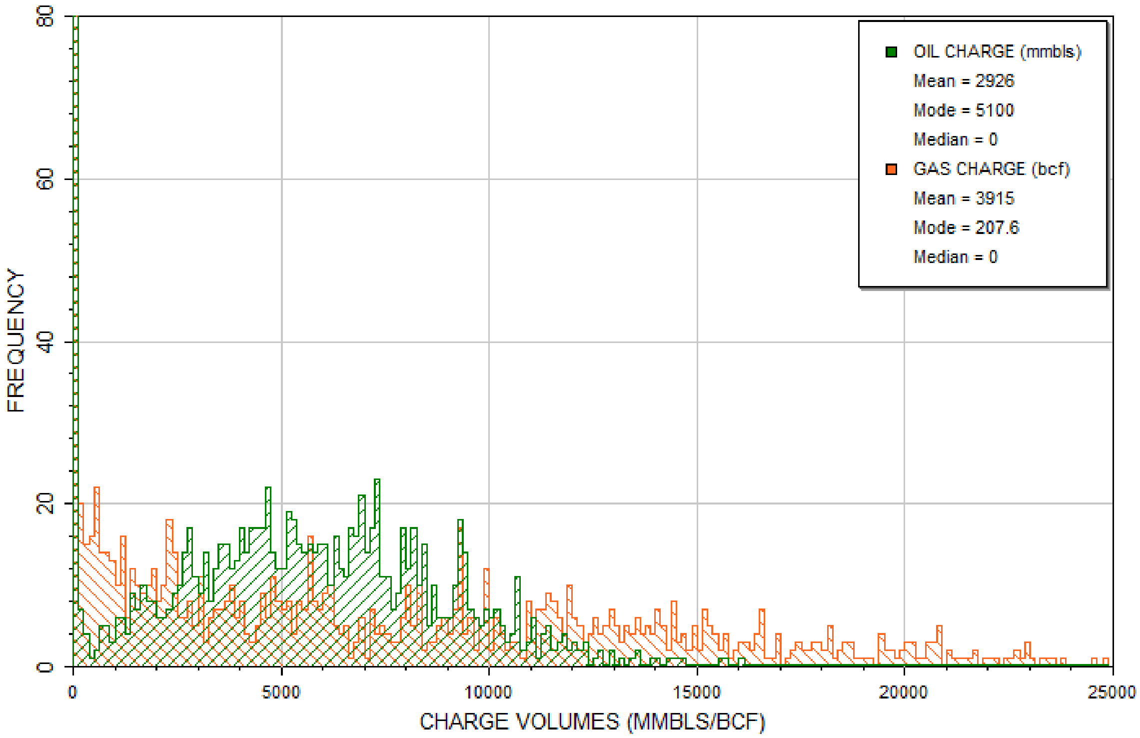

Figure 25. Monte Carlo hydrocarbon charge distribution.

gas charge volumes. This is expected because variation of the geothermal gradient will greatly impact the temperatures needed to produce gas volumes within the model. TOC,

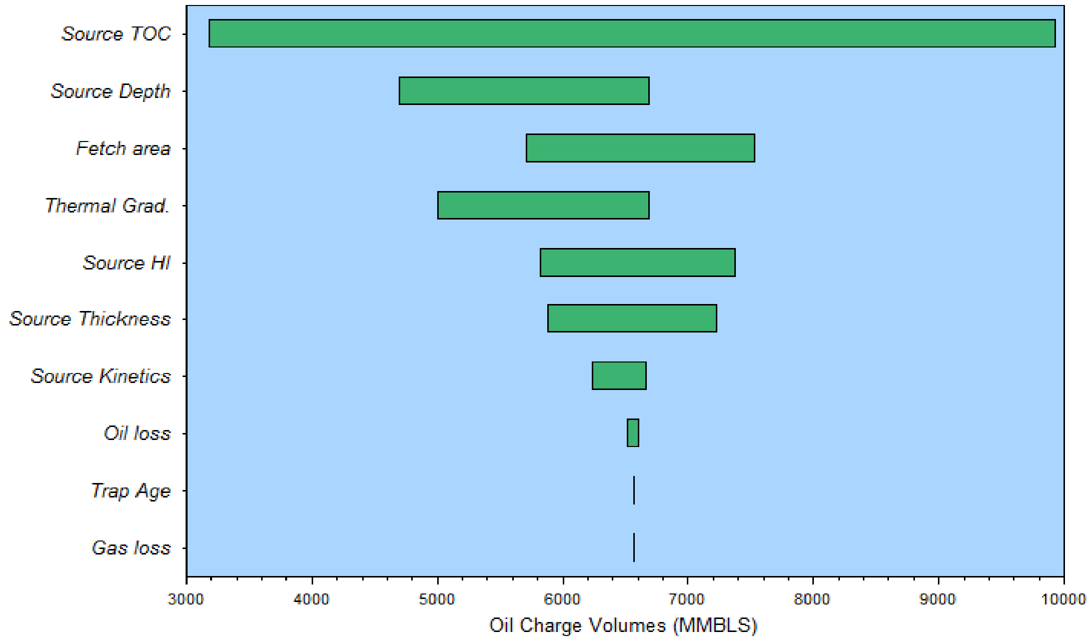

Figure 26. Oil charge volume tornado diagram.

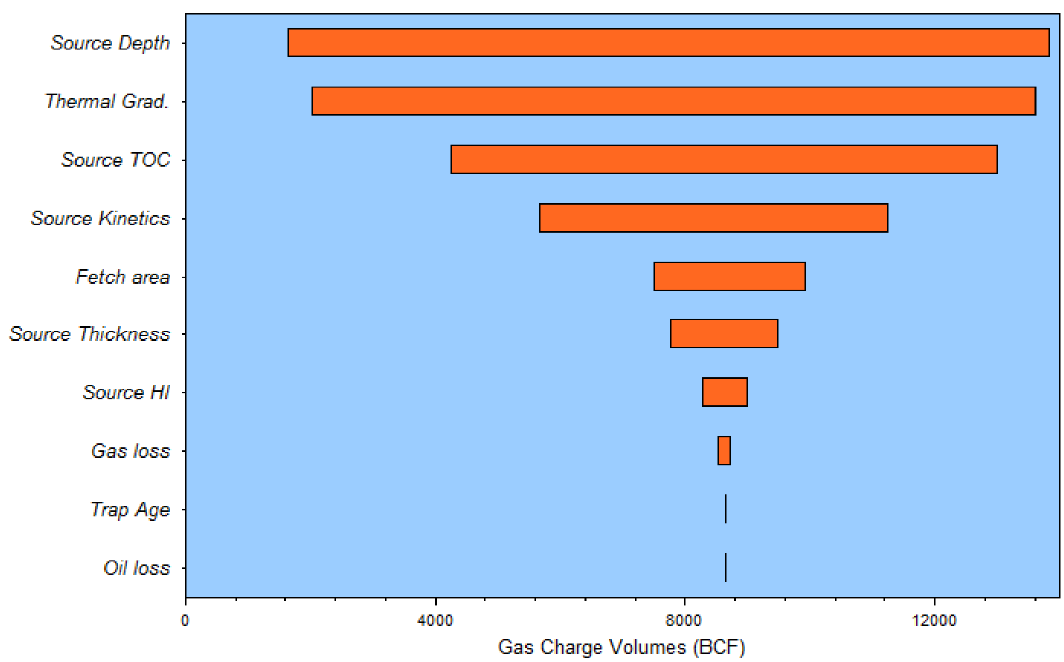

Figure 27. Gas charge volume tornado diagram.

source rock kinetics values, and average fetch area have relatively less of an influence on gas volumes, but are still critical parameters that influence the system. Leaked or spilled oil and gas, HI values, and trap age have minor influence on gas charge volumes.

7. PROPOSED FUTURE WORK

Continued analyses of the Simpson Group is crucial for gaining a better understanding of this petroleum system. Large amounts of uncertainty hinder modeled results during testing, and further work is needed to reduce these uncertainties. Better estimations of present day retained hydrocarbon volumes within the Simpson Group are needed, and can be better approximated from direct production of the members within the Simpson Group. Basal heat flow through time can also be better understood by using a greater distribution of 1-D models throughout the Midland Basin.

During testing of Working Hypotheses 2 and 3, we gained a better understanding of how increasing source rock TOC values impact the relative quantity and quality of generated hydrocarbons. In future works, we propose a much more quantitative method. Using a stoichiometric approach, total generated fluid volumes can be quantified for a range of TOC values. A similar methodology can be applied to Hydrogen Index values or a combination of both richness parameters. These analyses will further our understanding of how variation of input parameters impact generated hydrocarbon fluid volumes.

The mass balance analysis calculated within the Simpson-Ellenburger Pegasus Field represents only a portion of the Midland Basin. Above this play are three or more source rock intervals contributing hydrocarbons to five or more separate stacked reservoir intervals. Application of this methodology to these overlying formations is needed to determine if modeled results can match fluid distributions in each play given the assumptions and basin modeling parameters defined in this analysis. Once a calibrated model has been achieved for overlying plays, this workflow should be reproduced for neighboring fields. Ultimately, comparison of modeled properties with measured data for multiple fields and formations will allow earth scientist to further understand these petroleum systems.

Analyzing multiple overlying source rocks introduces a large amount of uncertainty when modeling fluid compositions due to in-reservoir mixing of different hydrocarbon fluids from different sources. Geochemical datasets are critical to future analyses, and should be included to better understand the large degree of fluid mixing in each stacked play within the Pegasus Field. Biomarker and diamondoid analyses are potentially two types of oil analyses that may be able to identify which source rocks are contributing hydrocarbons to the other five stacked plays.

8. CONCLUSION

Testing of Working Hypotheses 1 and 2 both resulted in two plausible models for charging the Pegasus Field Ellenburger structure. Downward vertical and horizontal intraformational charge from the Simpson Group both provide more than enough hydrocarbon fluids to fill the Ellenburger trap and ultimately spill hydrocarbons. Final mixed oil densities for both working hypotheses average 54.3 degree API, and are a close approximation to measured data. Per these observations, Working Hypotheses 1 and 2 are determined to be two possible scenarios of how the Pegasus Field was charged through time. Doubling TOC richness values in Working Hypothesis 3 increased the amount of generated and expelled hydrocarbons by a factor of 1.5 which provided more than enough hydrocarbons to fill the trap. Retained hydrocarbon volumes approximately double, and a final mixed oil API gravity of 51.2 is observed which is slightly lower than measured data. Per these observations, Working Hypothesis 3 is determined to be a possible model of the Simpson-Ellenburger petroleum system due to a fair match with measured data. When hydrocarbon generation kinetics are altered, 1.5 times the amount of oil and 15 times the amount of gas are retained within the Simpson source rock. Expelled hydrocarbon values are reduced, yet the model suggests enough hydrocarbons were expelled to fill the Ellenburger trap. Altering the source rock kinetic model resulted in a final mixed oil API gravity of 49 degrees API which is 4 degrees less than measured data. Although the largest deviation in final reservoir oil API gravity is observed during testing of Working Hypothesis 4, the oils are still representative of condensate type fluids. Due to a fair match between modeled results and measured data, Working Hypothesis 4 is determined to be a possible yet improbable model.

The most critical geologic processes and parameters that impact the generation, expulsion, migration, and entrapment of hydrocarbon fluids were determined during experimentation. Seal formation, migration and accumulation, burial history, and the timing of geologic events are determined to be the most critical geologic processes impacting the Pegasus Field Simpson-Ellenburger petroleum system. Key critical parameters affecting the model include source rock richness values (TOC and HI), thermal history, generation kinetics, and fetch area. In a post modeling sensitivity analysis, TOC richness values are determined to be the most sensitive parameter for the quantity of expelled oil volumes. Final source rock depth and geothermal gradient are determined to be the most sensitive parameter for the quantity of expelled gas volumes.

NOMENCLATURE

API	American Petroleum Institute
BBL	Barrels
BCF	Billion Cubic Feet
BEG	Bureau of Economic Geology
BHT	Bottom Hole Temperature
BOE	Barrels of Oil Equivalent
Ft	Feet
GOGI	Gas Oil Generation Index
GOR	Gas Oil Ratio
HI	Hydrogen Index
Km	Kilometers
Ma	Million Years
MMbbl	Million Barrels
OOIP	Original Oil In Place
SCF	Standard Cubic Feet
STP	Standard Temperature and Pressure
T	Temperature
TCF	Trillion Cubic Feet
TI	Transformation Index
TOC	Total Organic Carbon

TVD	True Vertical Depth
WH1	Working Hypothesis 1
WH2	Working Hypothesis 2
WH3	Working Hypothesis 3
WH4	Working Hypothesis 4
WTGS	West Texas Geologic Society

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APPENDIX

Parameter	P10	P50	P90	Distribution
Fetch area (%)	87	100	115	Lognormal
Source Depth (%)	85	100	115	Normal
Source Thickness (%)	90	100	110	Triangular
Source TOC (wt. %)	2	4	6	Normal
Source HI (mg/g TOC)	540	592	650	Lognormal
Oil loss (MMbbl/km^2)	0.6	0.8	1	Normal
Gas loss (bcf/km^2)	0	0.5	1	Triangular
Thermal Gradient (%)	85	100	115	Normal
Source Kinetics (Deg. C)	122	132	142	Triangular
Trap Age (Ma)	290	300	310	Normal

Table A- 1. Input parameters used in the Monte-Carlo simulation.

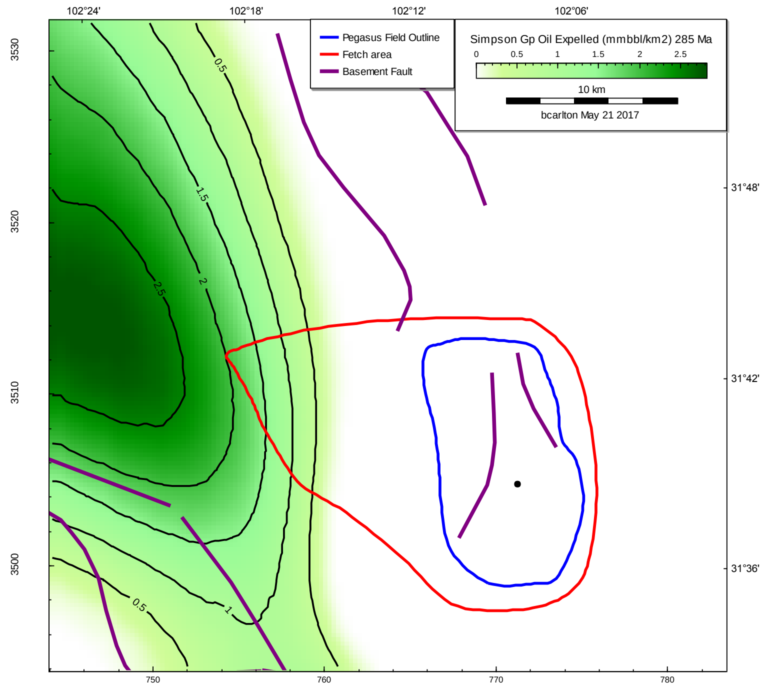

Figure A- 1. Oil Expelled from the Simpson Group at 285 Ma for Working Hypotheses 1 and 2.

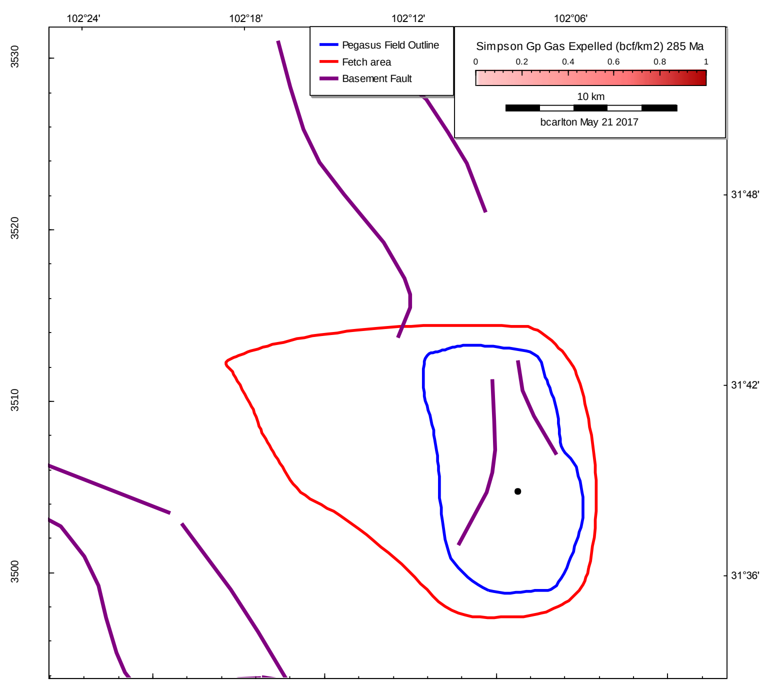

Figure A- 2. Gas Expelled from the Simpson Group at 285 Ma for Working Hypotheses 1 and 2.

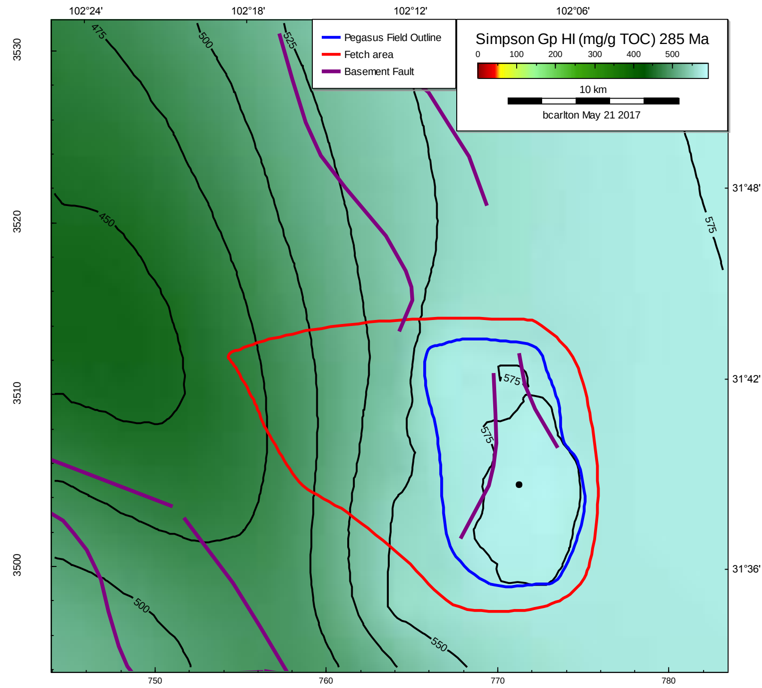

Figure A- 3. Simpson Group Hydrogen Index at 285 Ma for Working Hypotheses 1 and 2.

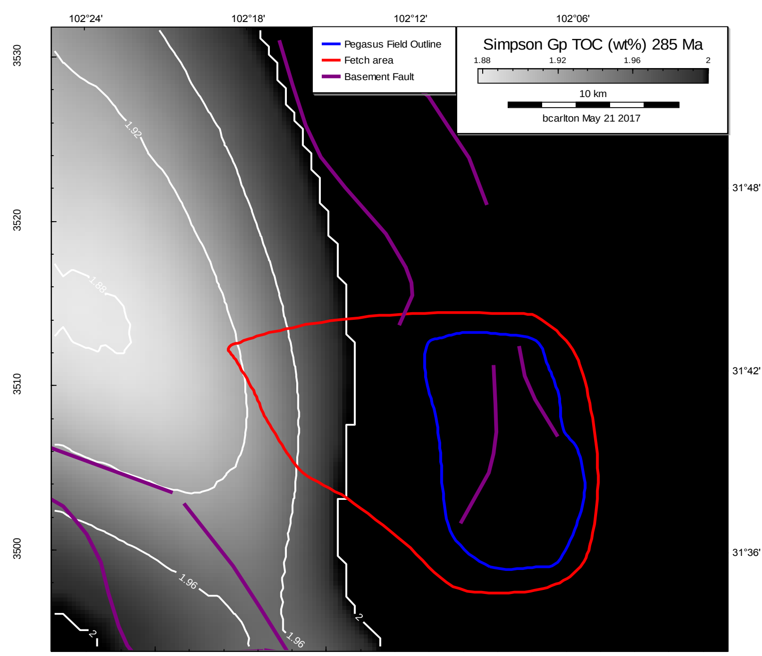

Figure A- 4. Simpson Group Total Organic Carbon at 285 Ma for Working Hypotheses 1 and 2.

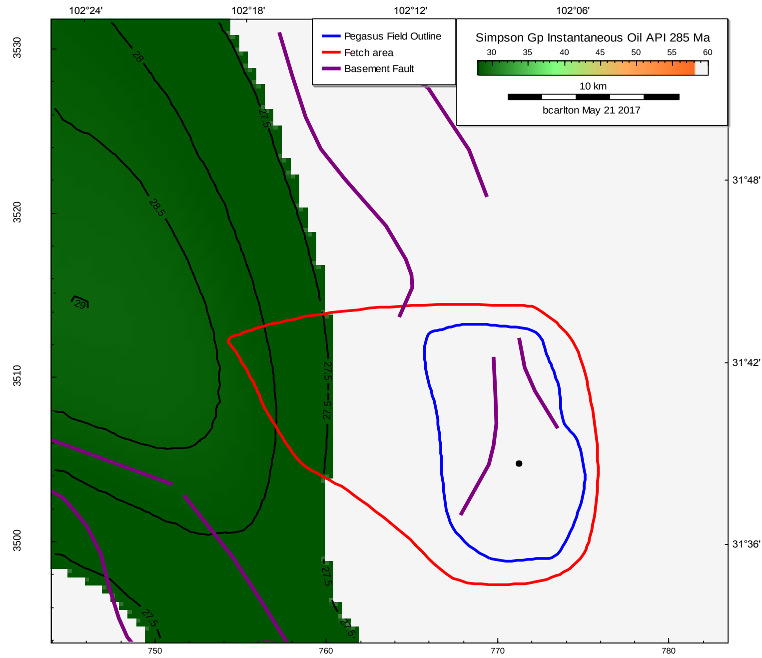

Figure A- 5. Simpson Group instantaneous oil API gravity at 285 Ma for Working Hypotheses 1 and 2.

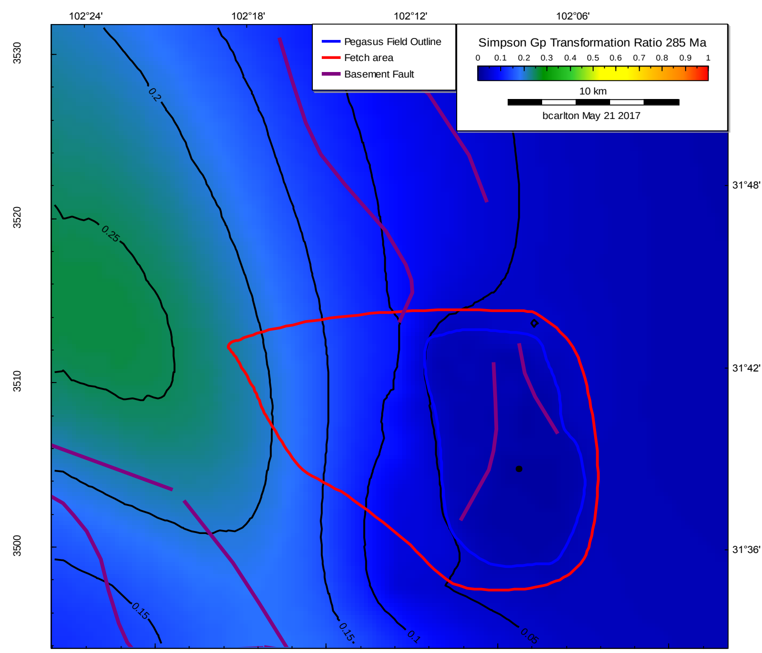

Figure A- 6. Simpson Group transformation ratio at 285 Ma for Working Hypotheses 1 and 2.

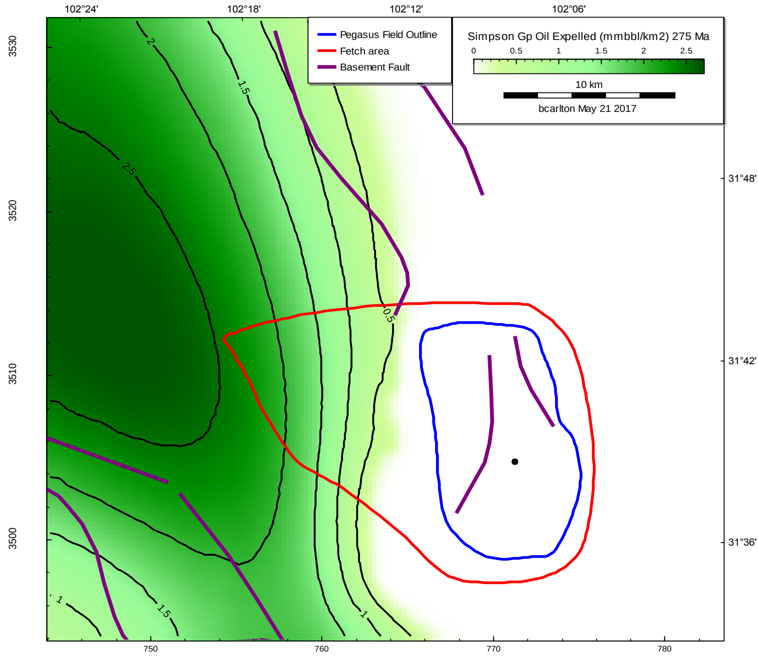

Figure A- 7. Oil Expelled from the Simpson Group at 275 Ma for Working Hypotheses 1 and 2.

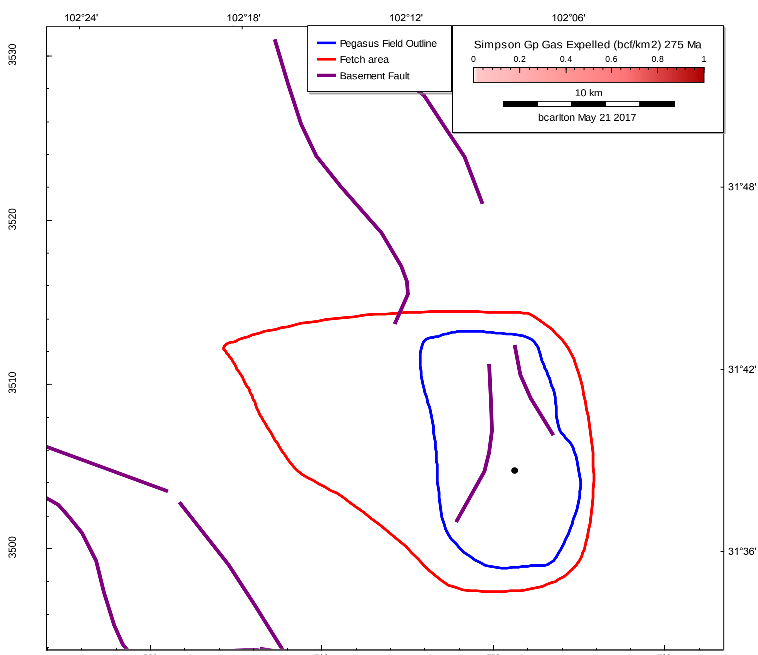

Figure A- 8. Gas Expelled from the Simpson Group at 275 Ma for Working Hypotheses 1 and 2.

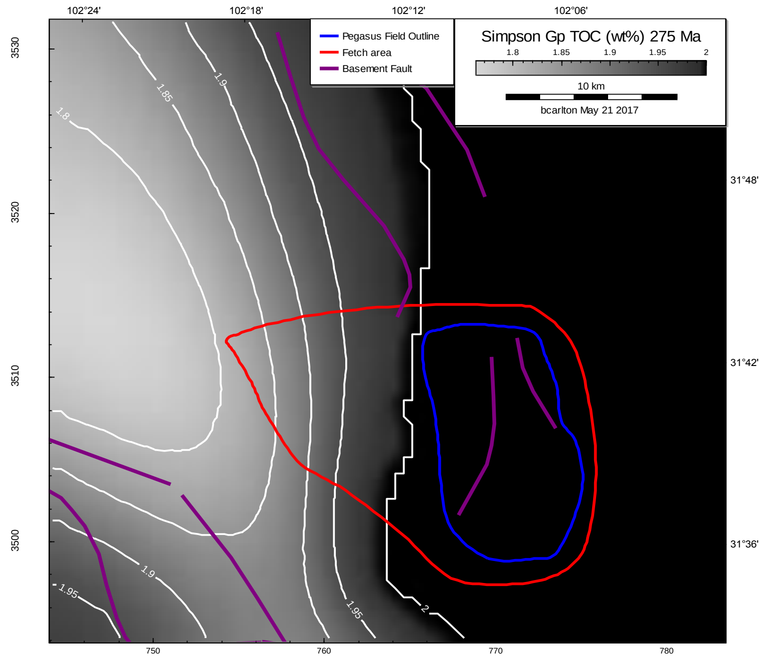

Figure A- 9. Simpson Group Total Organic Carbon at 275 Ma for Working Hypotheses 1 and 2.

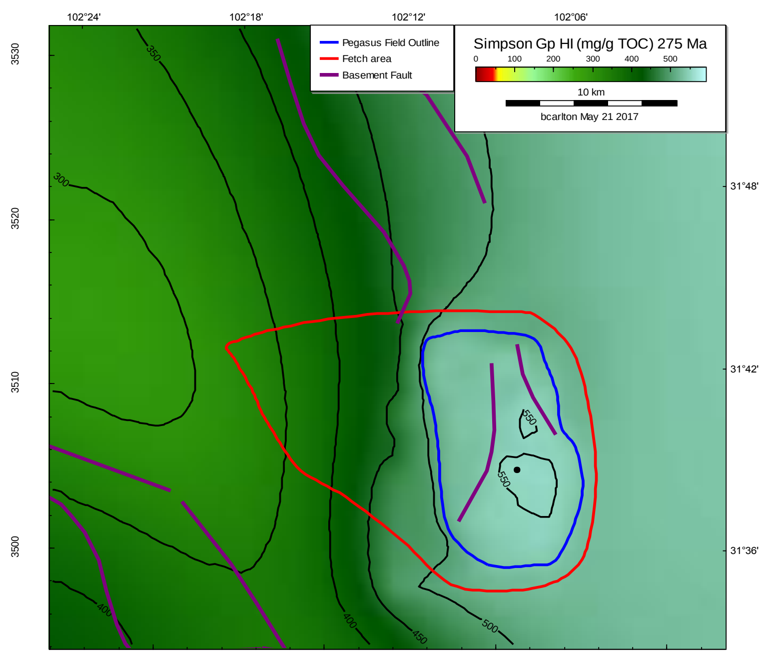

Figure A- 10. Simpson Group Hydrogen Index at 275 Ma for Working Hypotheses 1 and 2.

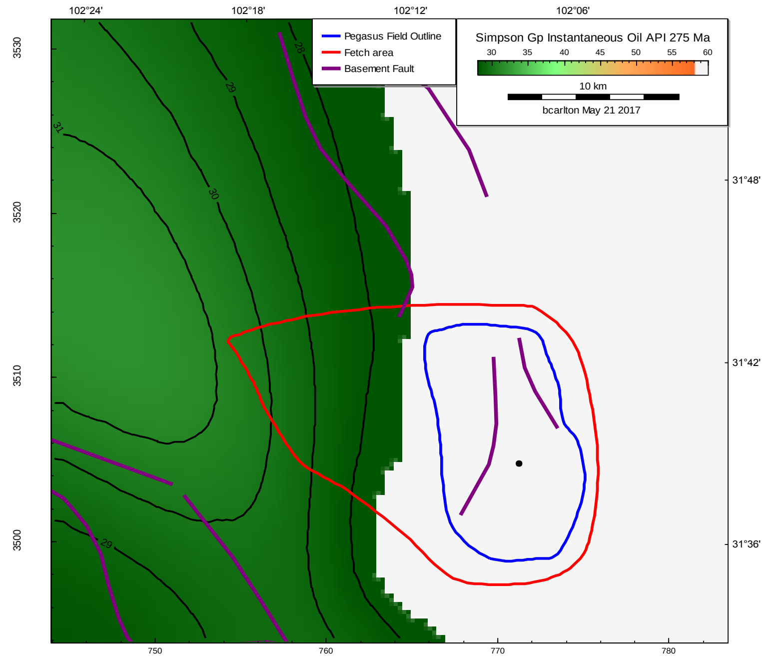

Figure A- 11. Simpson Group instantaneous oil API gravity at 275 Ma for Working Hypotheses 1 and 2.

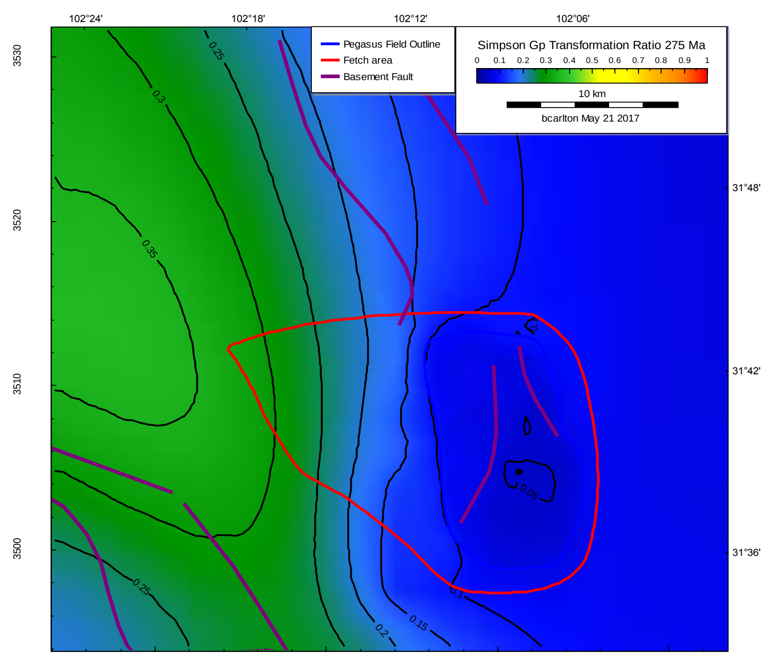

Figure A- 12. Simpson Group transformation ratio at 275 Ma for Working Hypotheses 1 and 2.

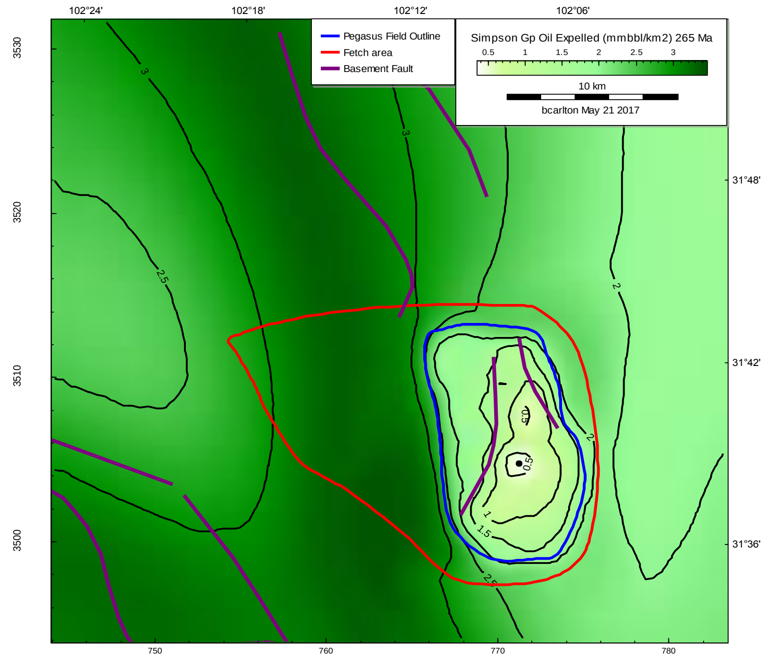

Figure A- 13. Oil Expelled from the Simpson Group at 265 Ma for Working Hypotheses 1 and 2.

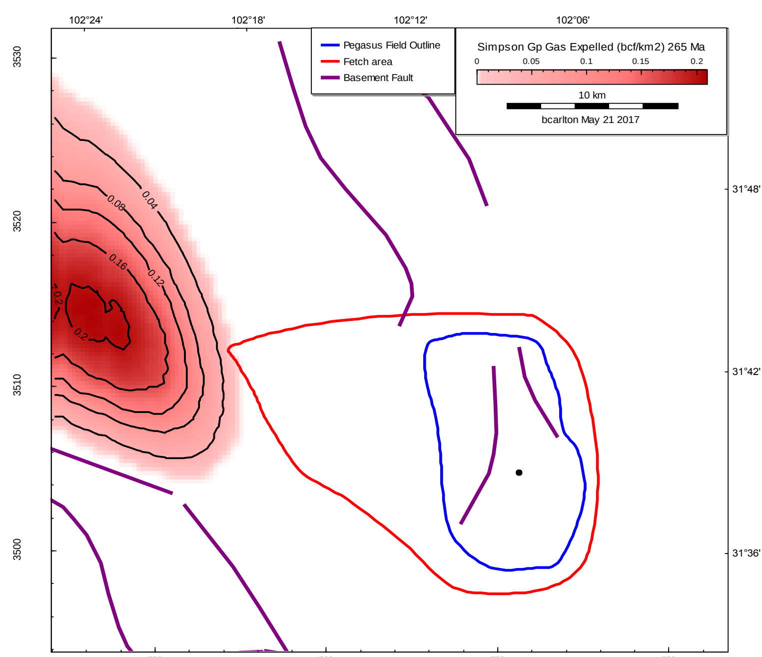

Figure A- 14. Gas Expelled from the Simpson Group at 265 Ma for Working Hypotheses 1 and 2.

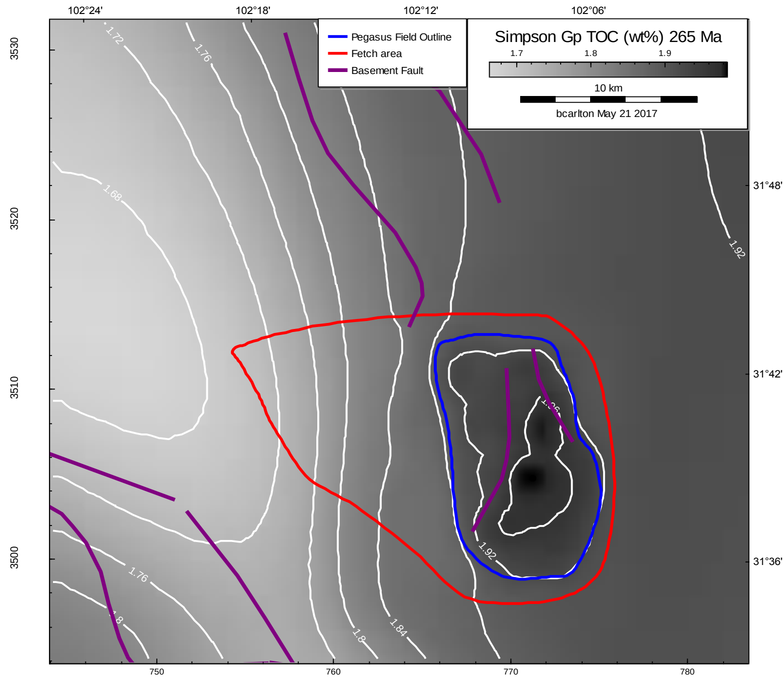

Figure A- 15. Simpson Group Total Organic Carbon at 265 Ma for Working Hypotheses 1 and 2.

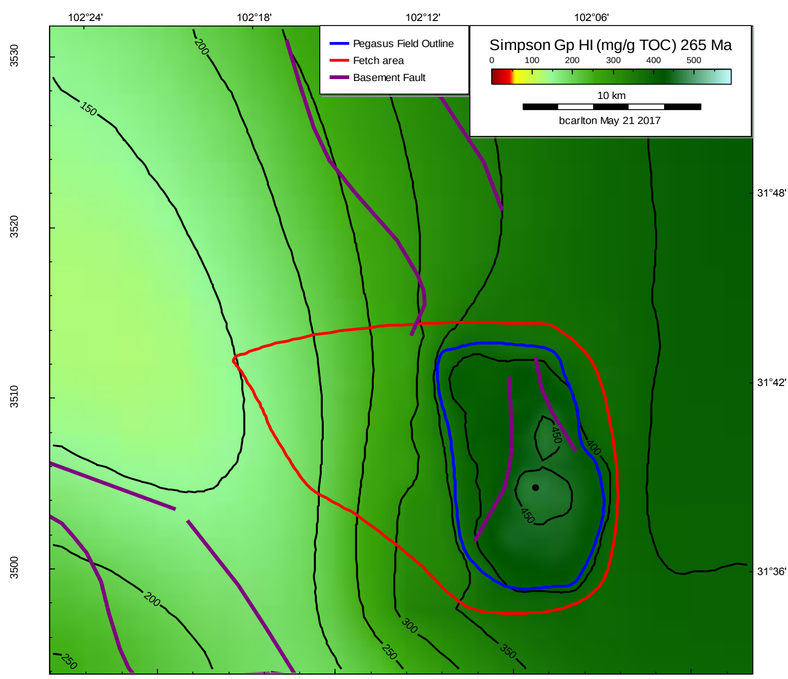

Figure A- 16. Simpson Group Hydrogen Index at 265 Ma for Working Hypotheses 1 and 2.

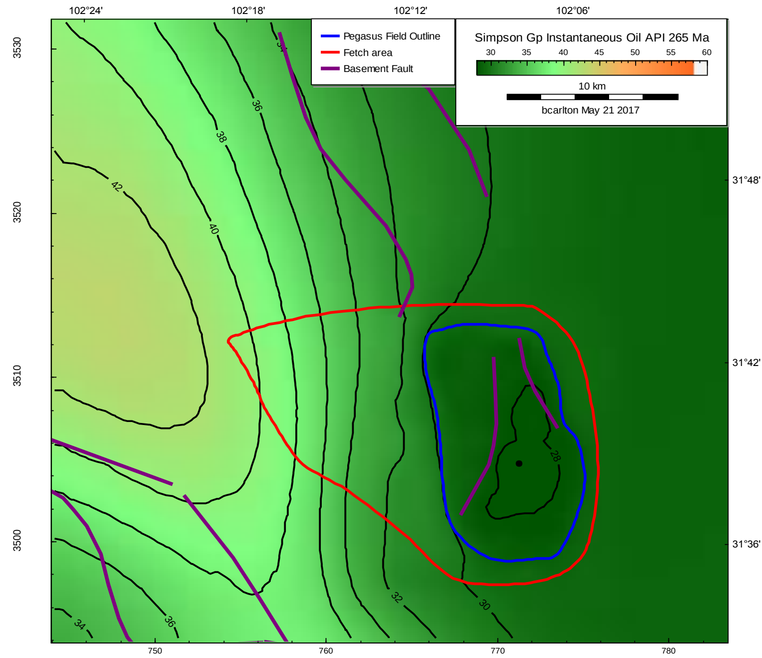

Figure A- 17. Simpson Group instantaneous oil API gravity at 265 Ma for Working Hypotheses 1 and 2.

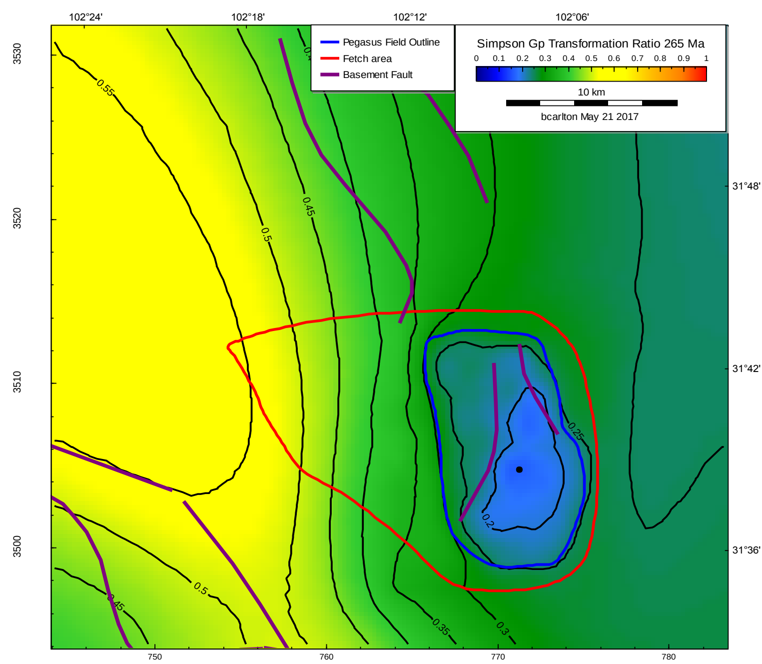

Figure A- 18. Simpson Group transformation ratio at 265 Ma for Working Hypotheses 1 and 2.

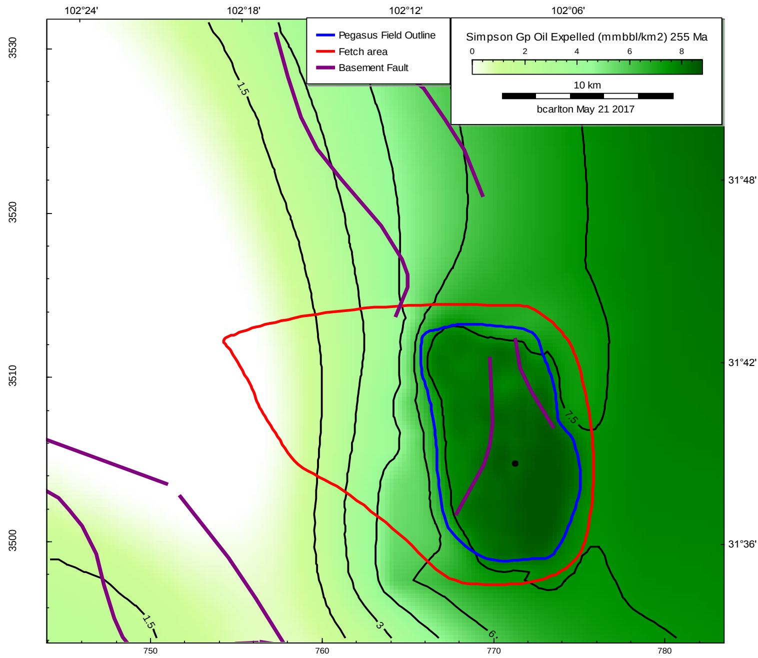

Figure A- 19. Oil Expelled from the Simpson Group at 255 Ma for Working Hypotheses 1 and 2.

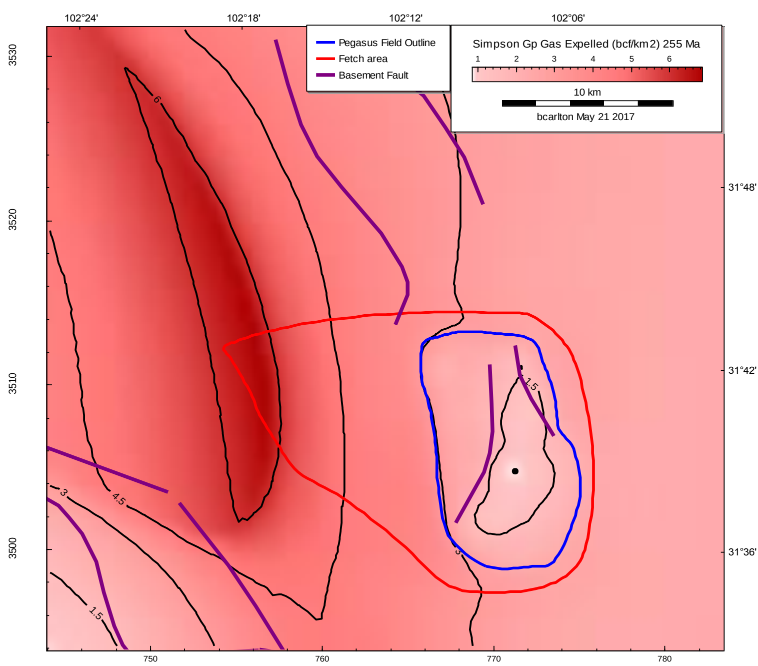

Figure A- 20. Gas Expelled from the Simpson Group at 255 Ma for Working Hypotheses 1 and 2.

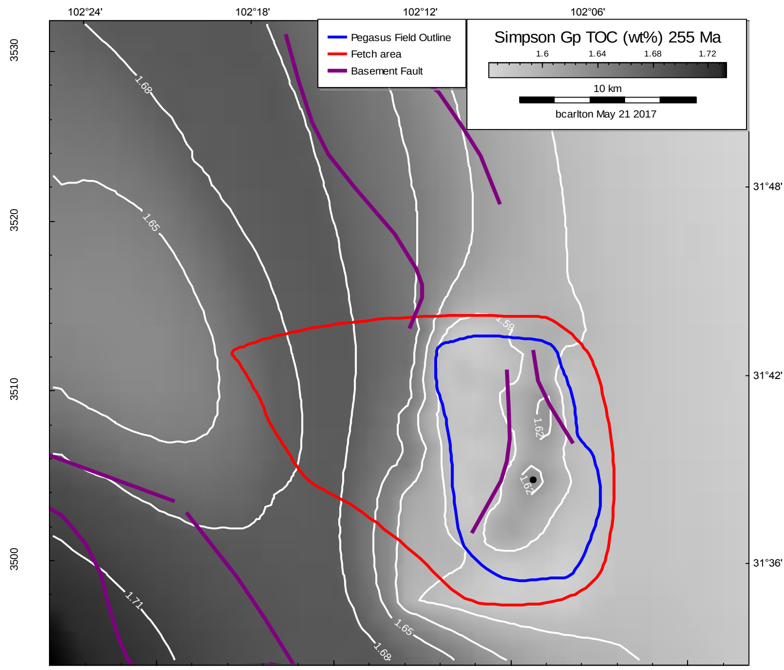

Figure A- 21. Simpson Group Total Organic Carbon at 255 Ma for Working Hypotheses 1 and 2.

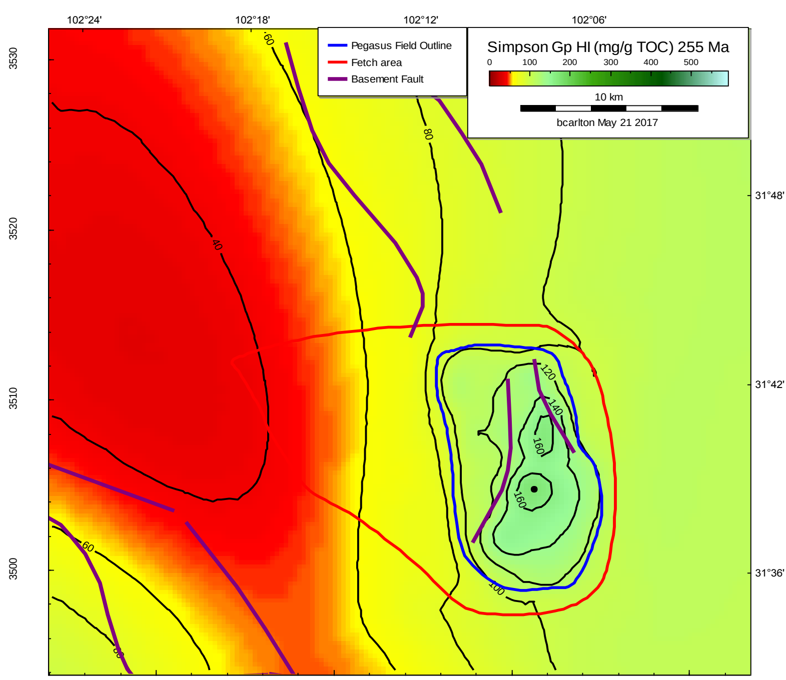

Figure A- 22. Simpson Group Hydrogen Index at 255 Ma for Working Hypotheses 1 and 2.

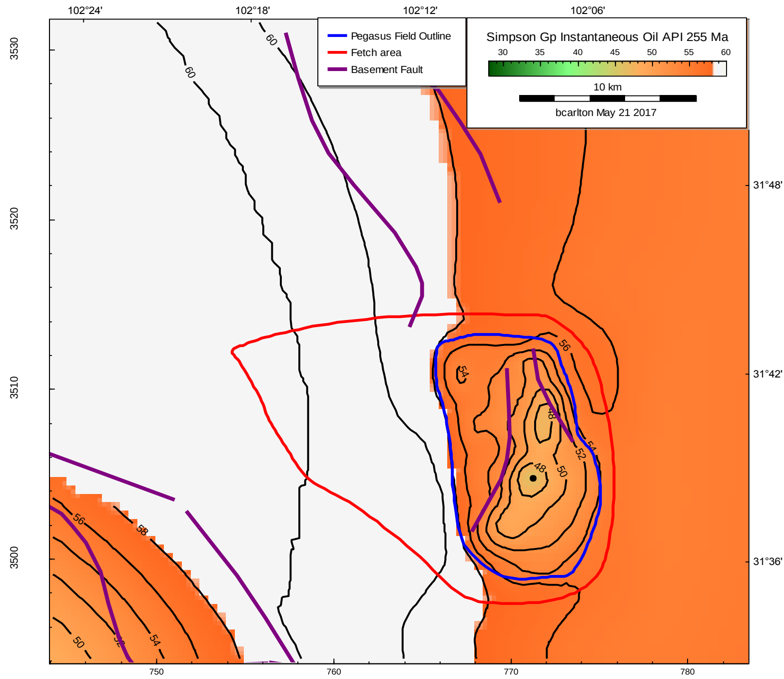

Figure A- 23. Simpson Group instantaneous oil API gravity at 255 Ma for Working Hypotheses 1 and 2.

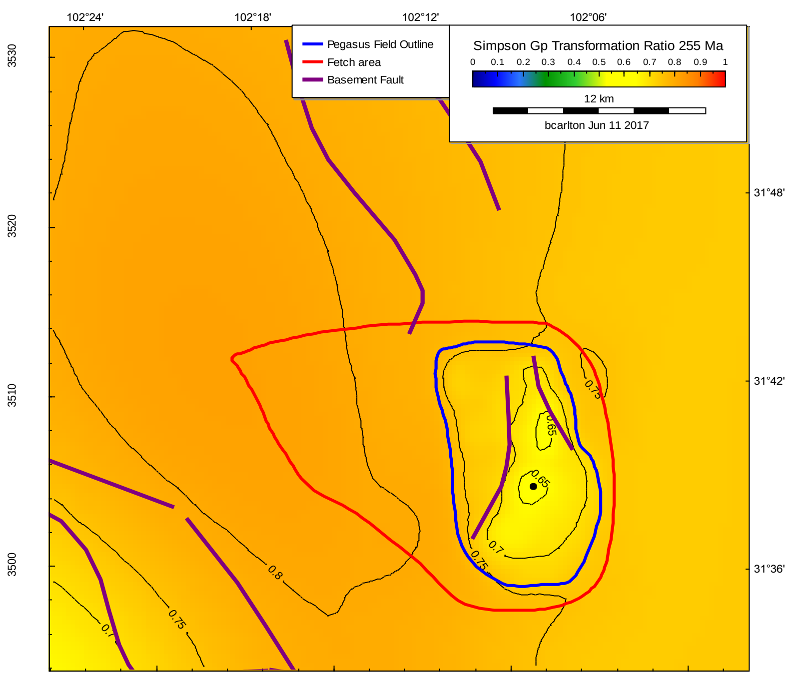

Figure A- 24. Simpson Group transformation ratio at 255 Ma for Working Hypotheses 1 and 2.

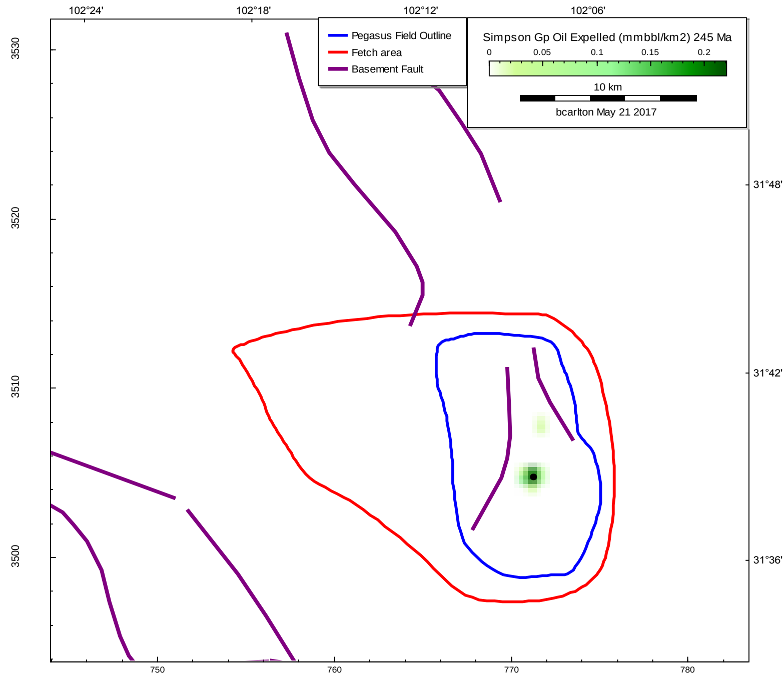

Figure A- 25. Oil Expelled from the Simpson Group at 245 Ma for Working Hypotheses 1 and 2.

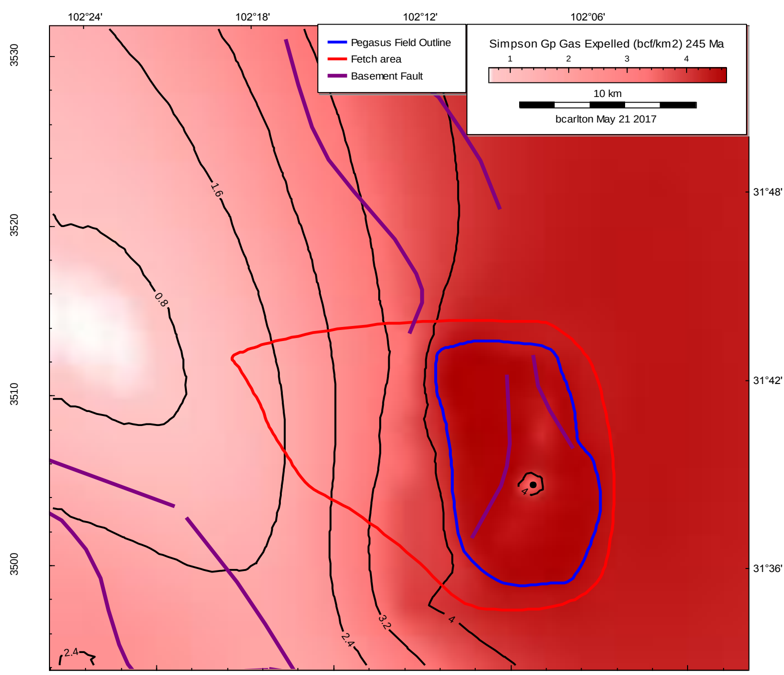

Figure A- 26. Gas Expelled from the Simpson Group at 245 Ma for Working Hypotheses 1 and 2.

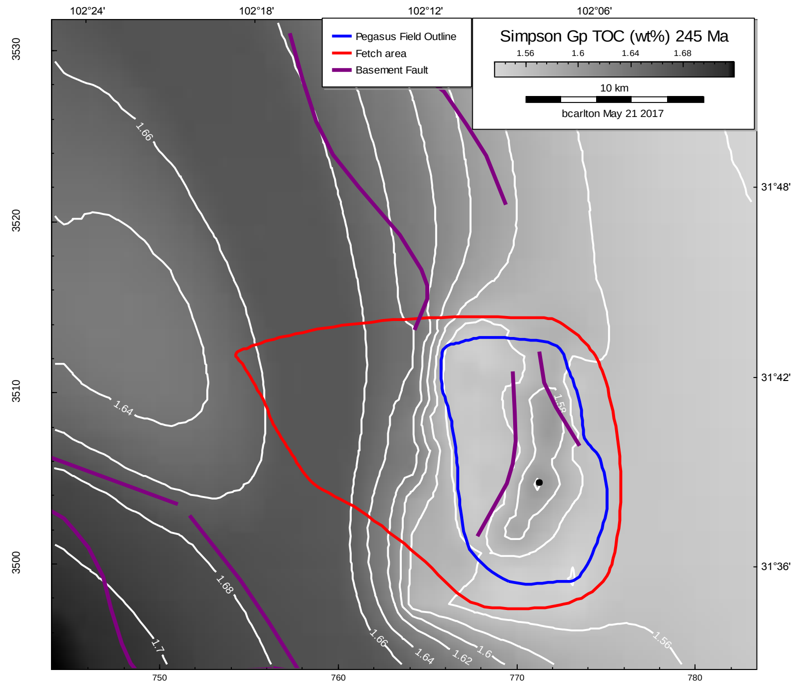

Figure A- 27. Simpson Group Total Organic Carbon at 245 Ma for Working Hypotheses 1 and 2.

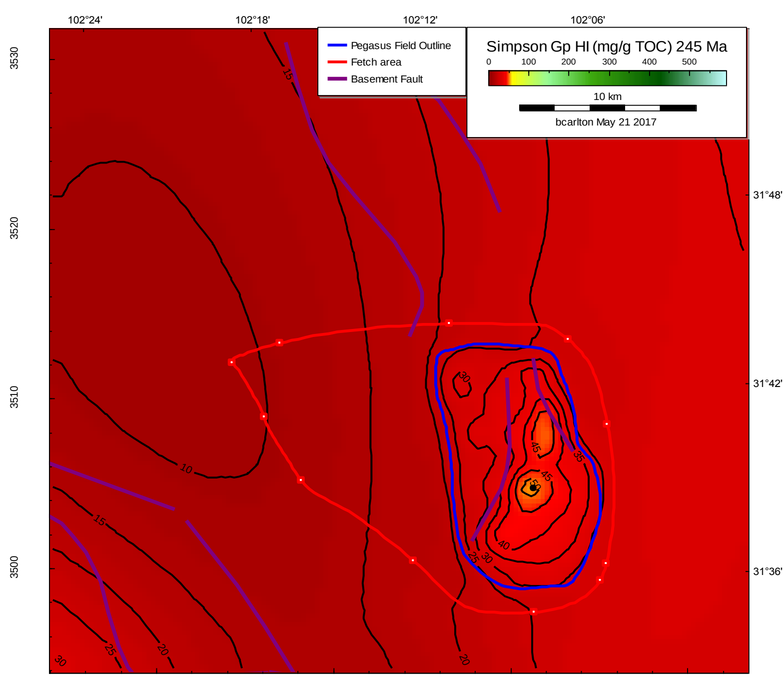

Figure A- 28. Simpson Group Hydrogen Index at 245 Ma for Working Hypotheses 1 and 2.

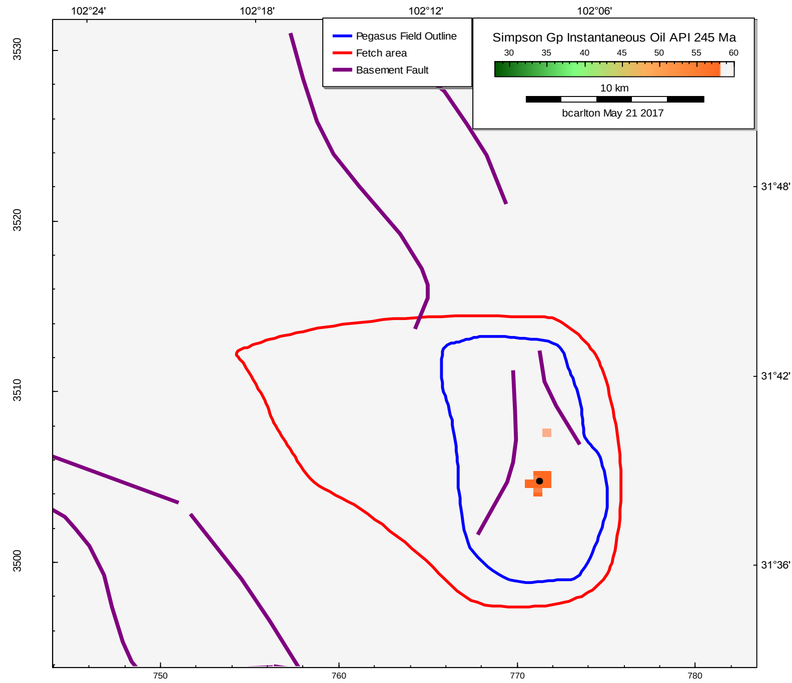

Figure A- 29. Simpson Group instantaneous oil API gravity at 245 Ma for Working Hypotheses 1 and 2.

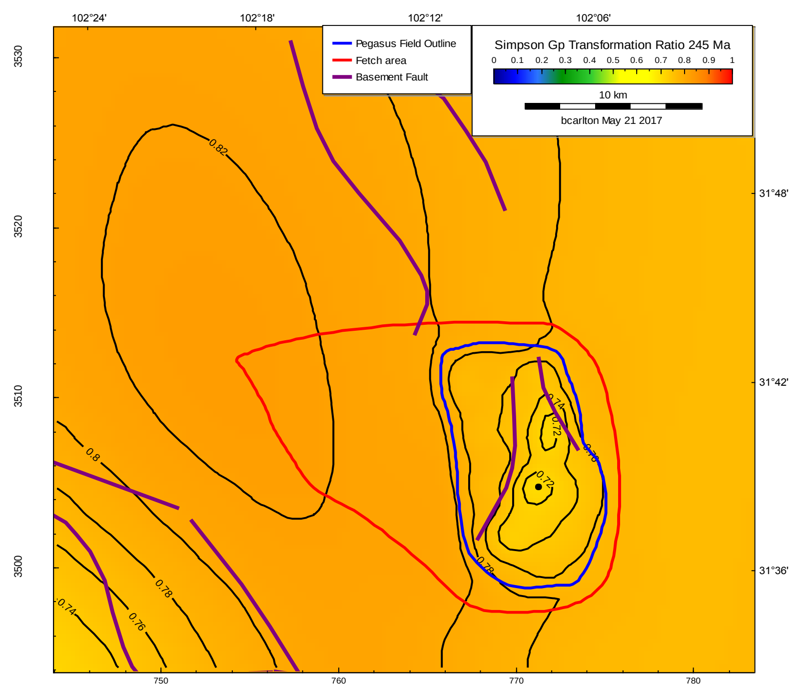

Figure A- 30. Simpson Group transformation ratio at 245 Ma for Working Hypotheses 1 and 2.

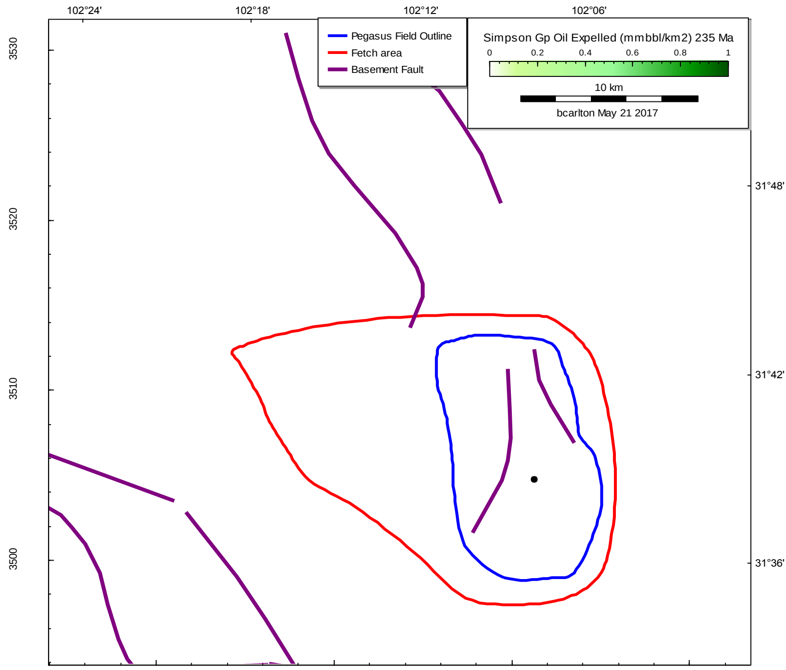

Figure A- 31. Oil Expelled from the Simpson Group at 235 Ma for Working Hypotheses 1 and 2.

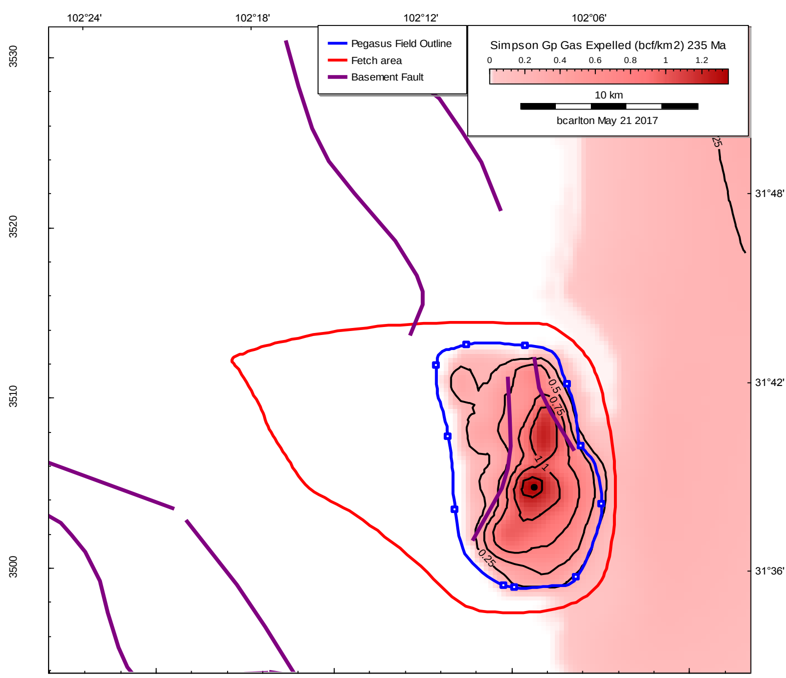

Figure A- 32. Gas Expelled from the Simpson Group at 235 Ma for Working Hypotheses 1 and 2.

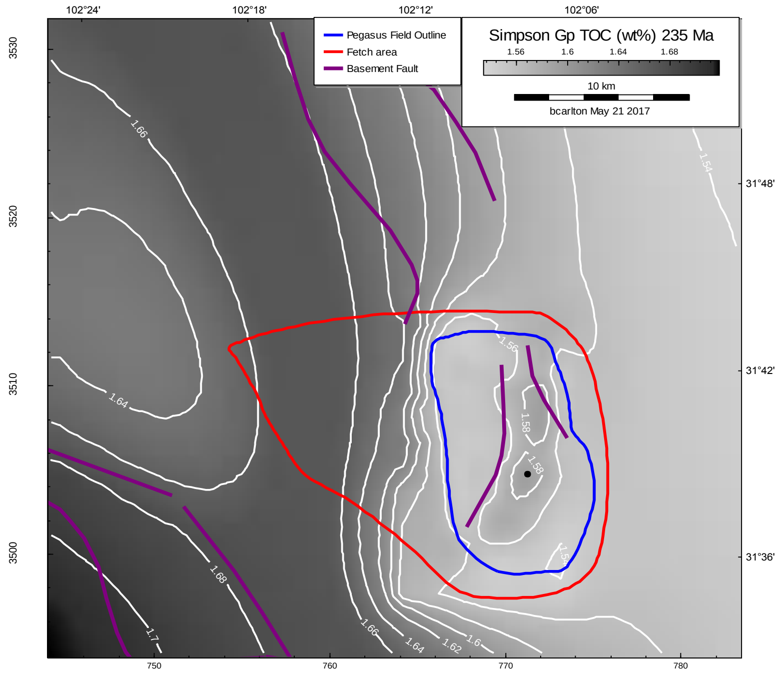

Figure A- 33. Simpson Group Total Organic Carbon at 235 Ma for Working Hypotheses 1 and 2.

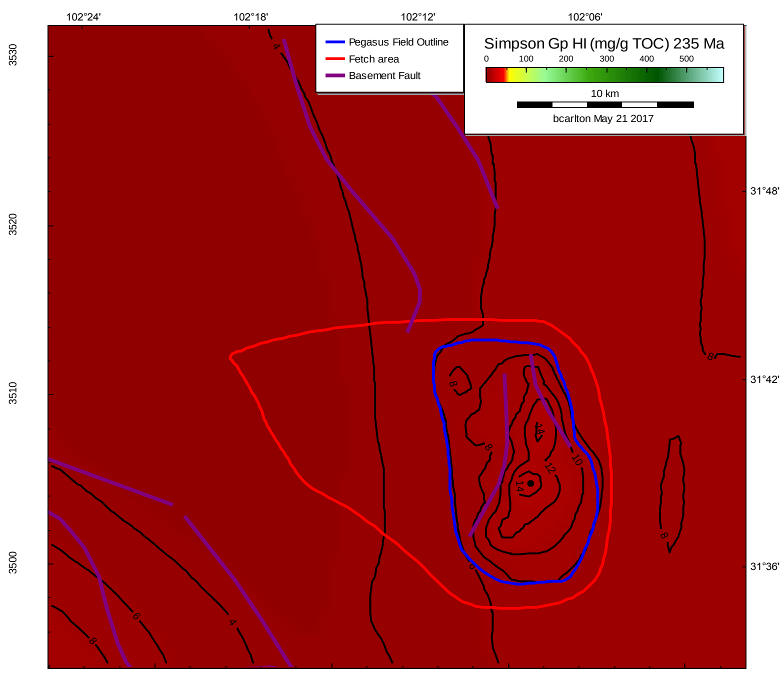

Figure A- 34. Simpson Group Hydrogen Index at 235 Ma for Working Hypotheses 1 and 2.

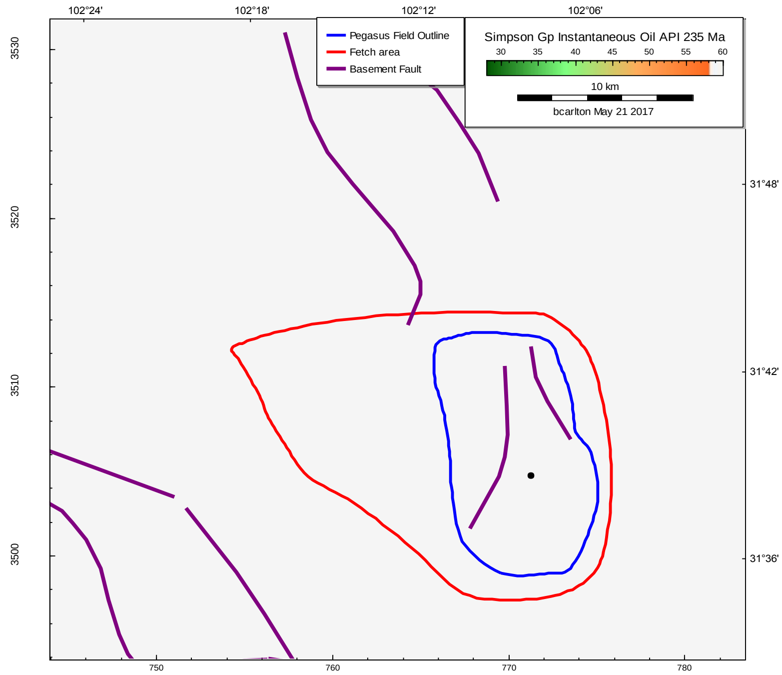

Figure A- 35. Simpson Group instantaneous oil API gravity at 235 Ma for Working Hypotheses 1 and 2.

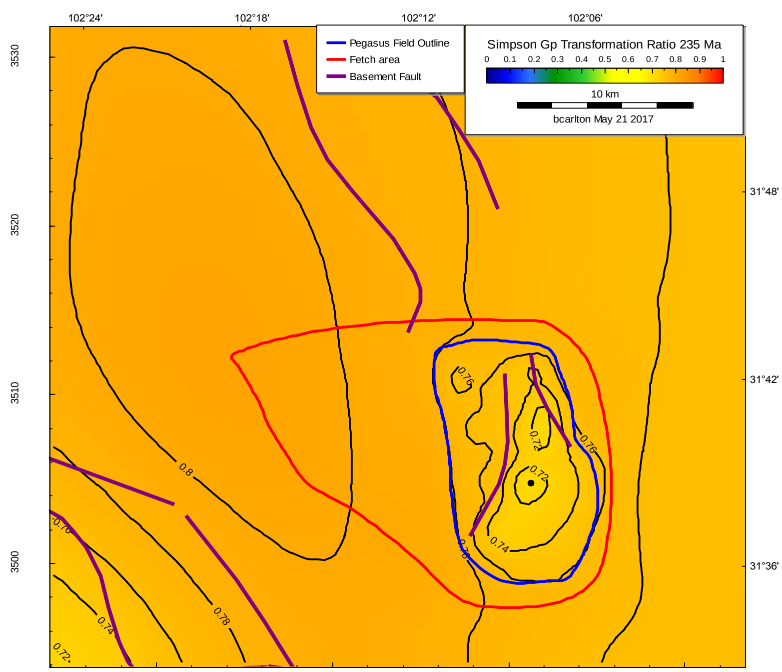

Figure A- 36. Simpson Group transformation ratio at 235 Ma for Working Hypotheses 1 and 2.

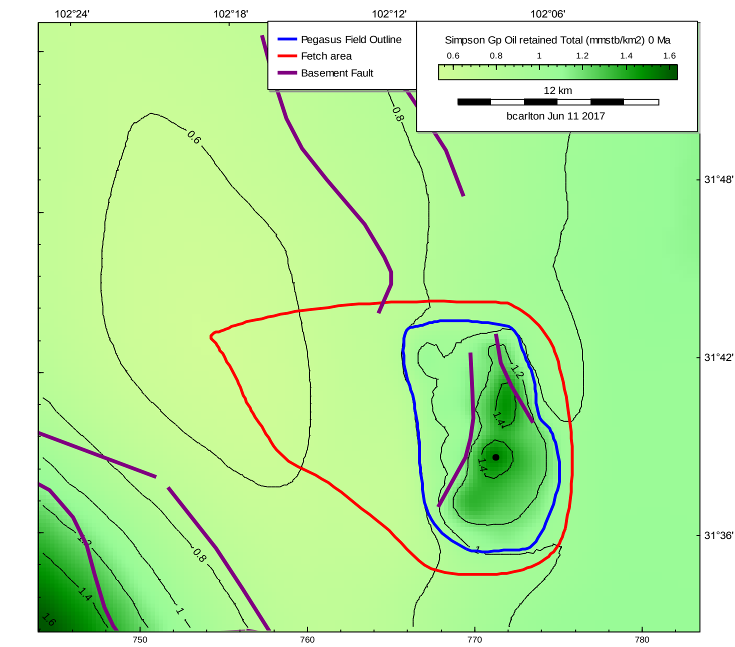

Figure A- 37. Simpson Group total oil retained at 0 Ma for Working Hypotheses 1 and 2.

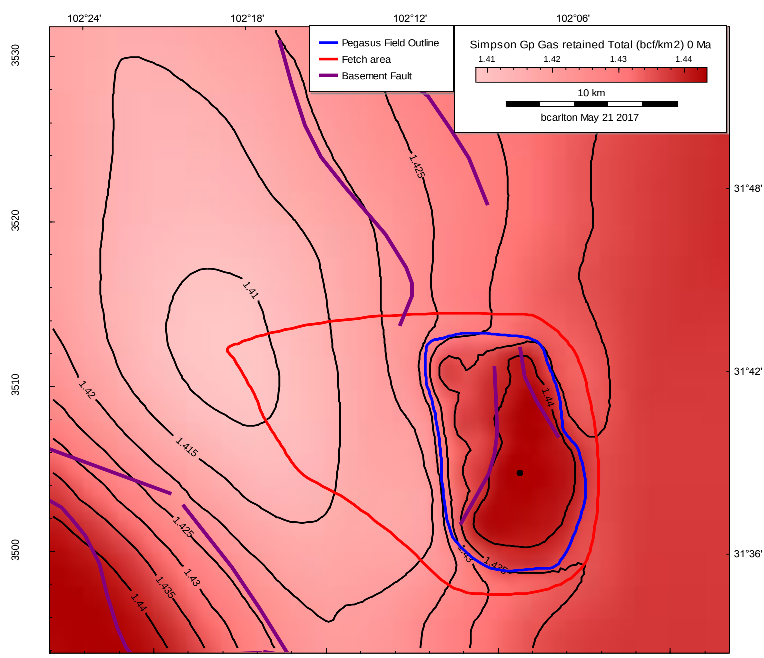

Figure A- 38. Simpson Group total gas retained at 0 Ma for Working Hypotheses 1 and 2.

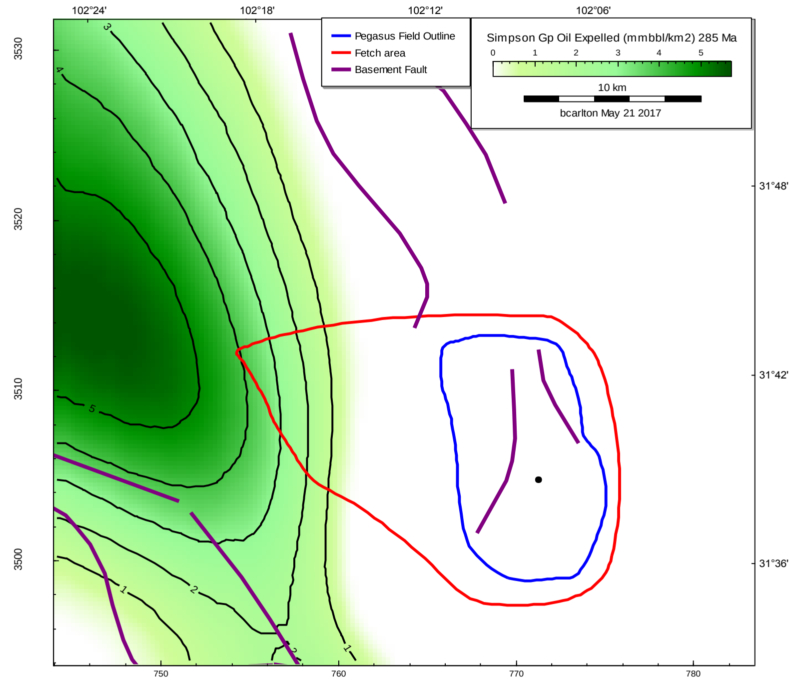

Figure A- 39. Oil Expelled from the Simpson Group at 285 Ma for Working Hypothesis 3.

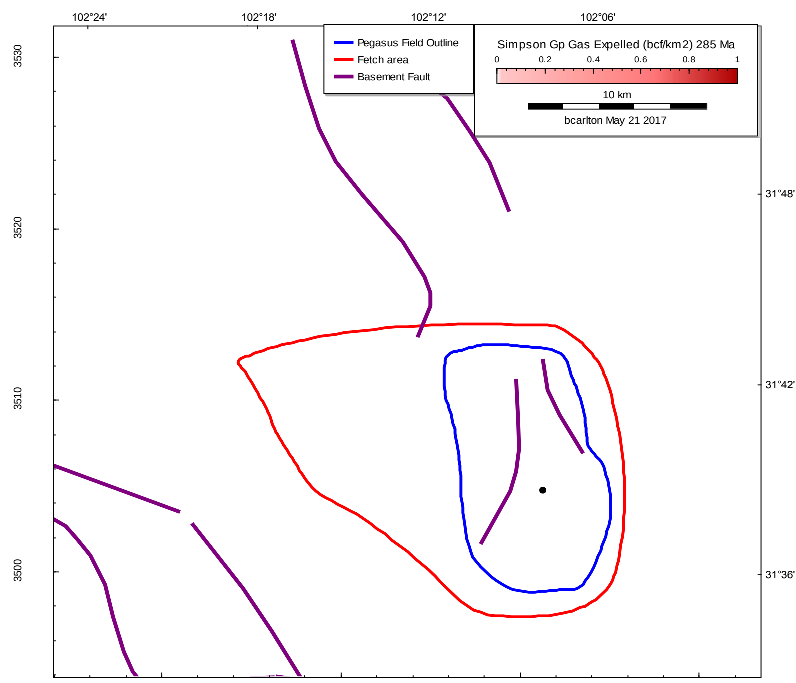

Figure A- 40. Gas Expelled from the Simpson Group at 285 Ma for Working Hypothesis 3.

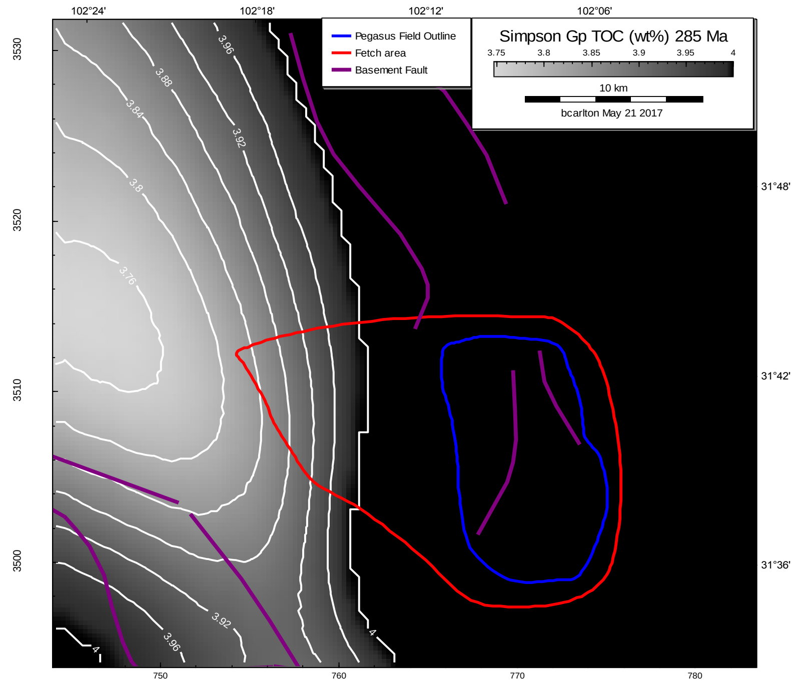

Figure A- 41. Simpson Group Total Organic Carbon at 285 Ma for Working Hypothesis 3.

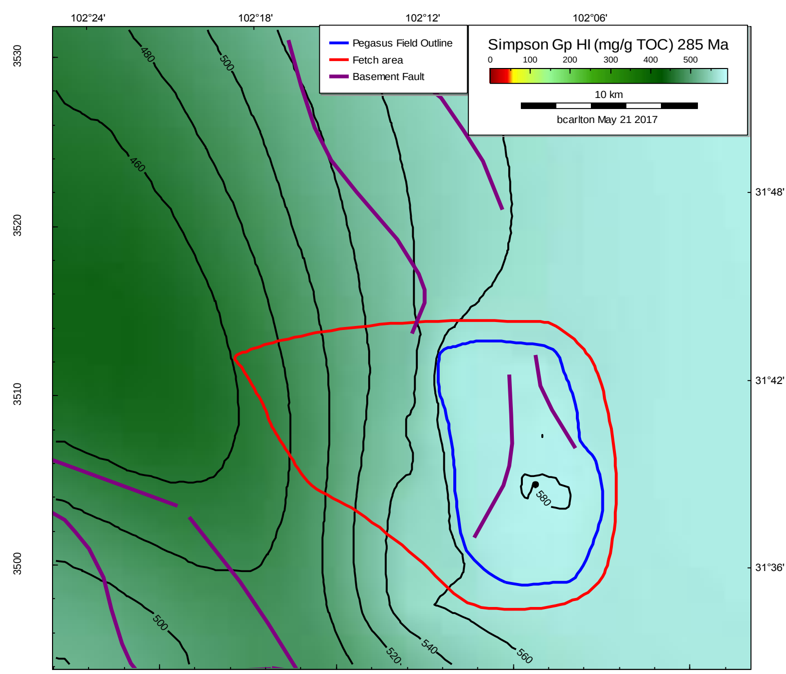

Figure A- 42. Simpson Group Hydrogen Index at 285 Ma for Working Hypothesis 3.

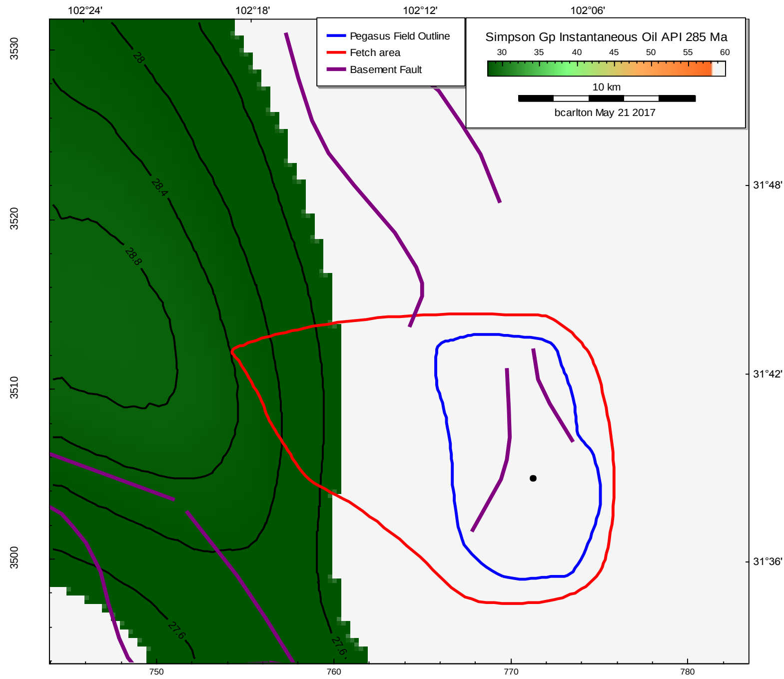

Figure A- 43. Simpson Group instantaneous oil API gravity at 285 Ma for Working Hypotheses 3.

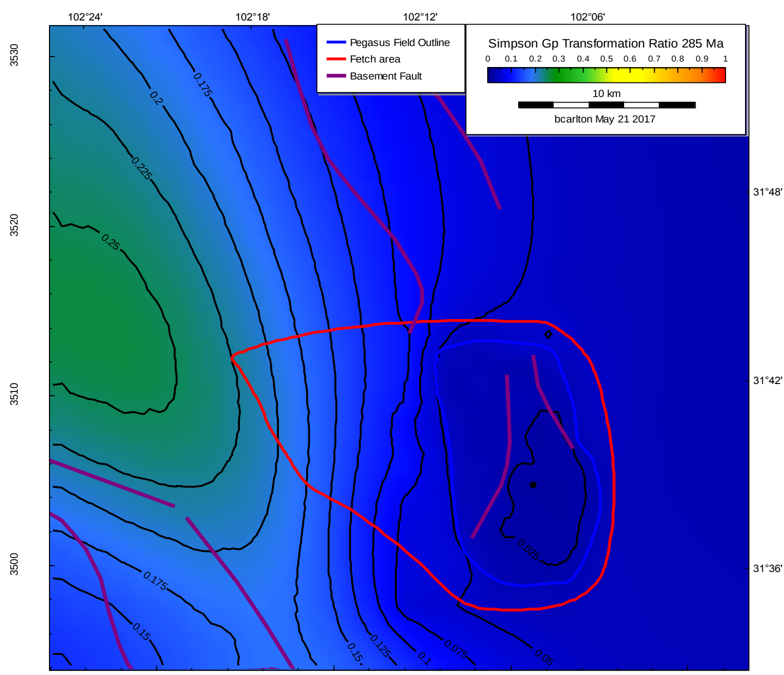

Figure A- 44. Simpson Group transformation ratio at 285 Ma for Working Hypothesis 3.

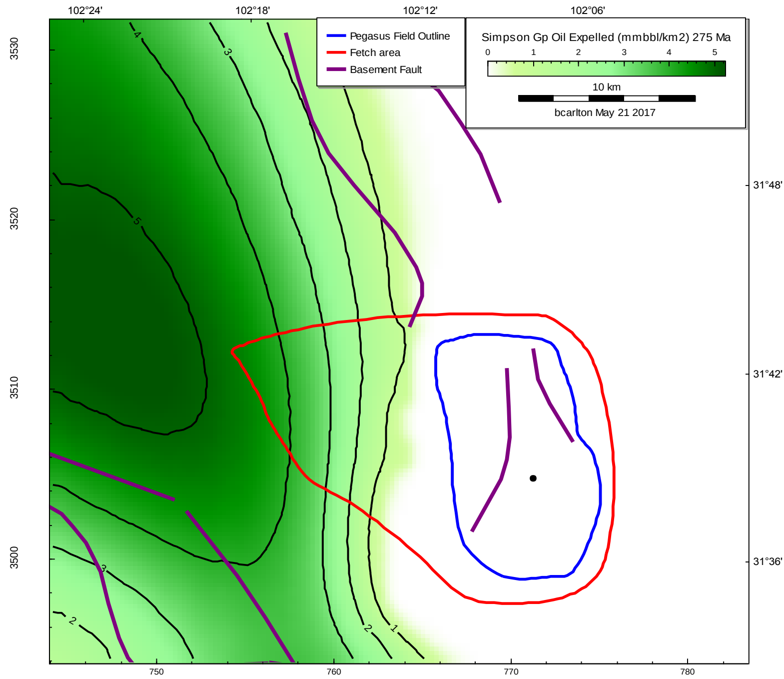

Figure A- 45. Oil Expelled from the Simpson Group at 275 Ma for Working Hypothesis 3.

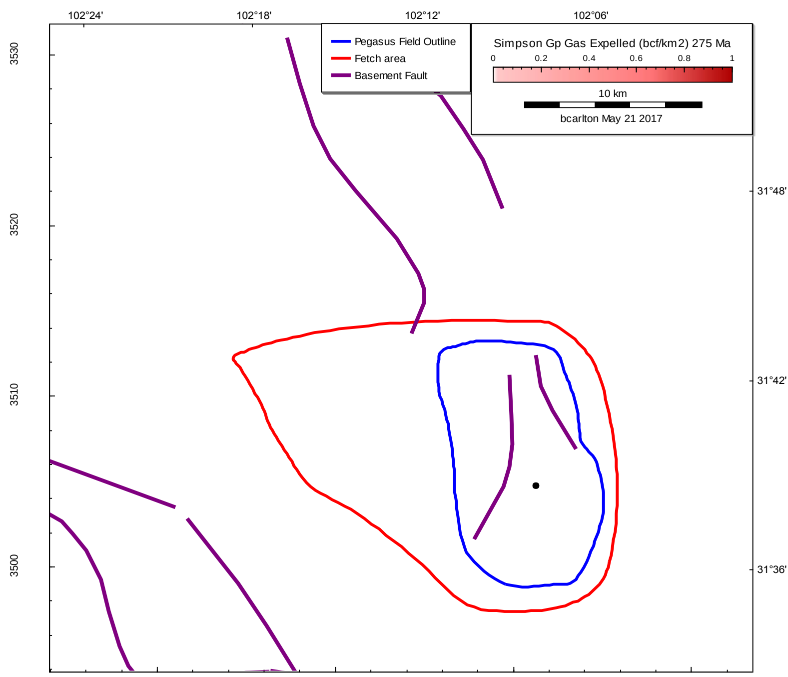

Figure A- 46. Gas Expelled from the Simpson Group at 275 Ma for Working Hypothesis 3.

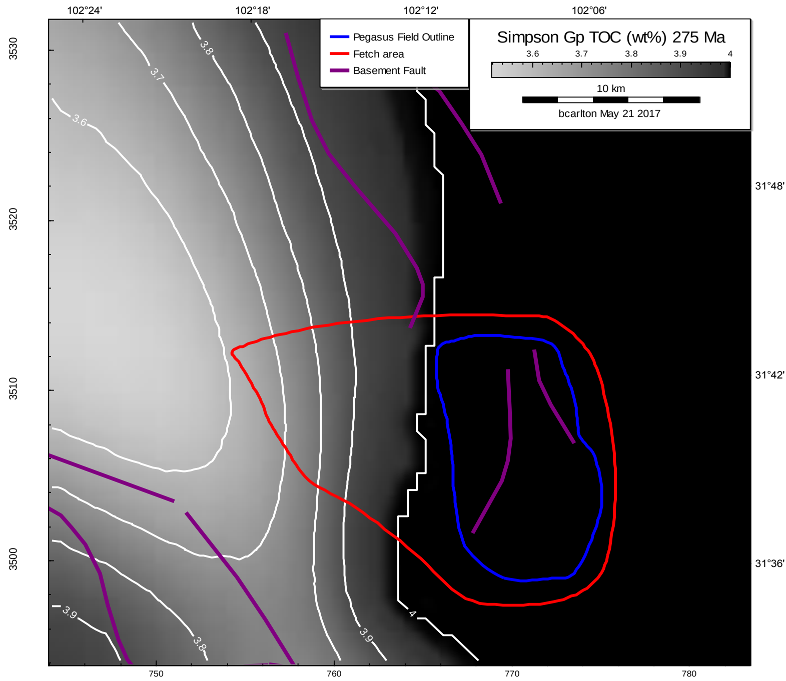

Figure A- 47. Simpson Group Total Organic Carbon at 275 Ma for Working Hypothesis 3.

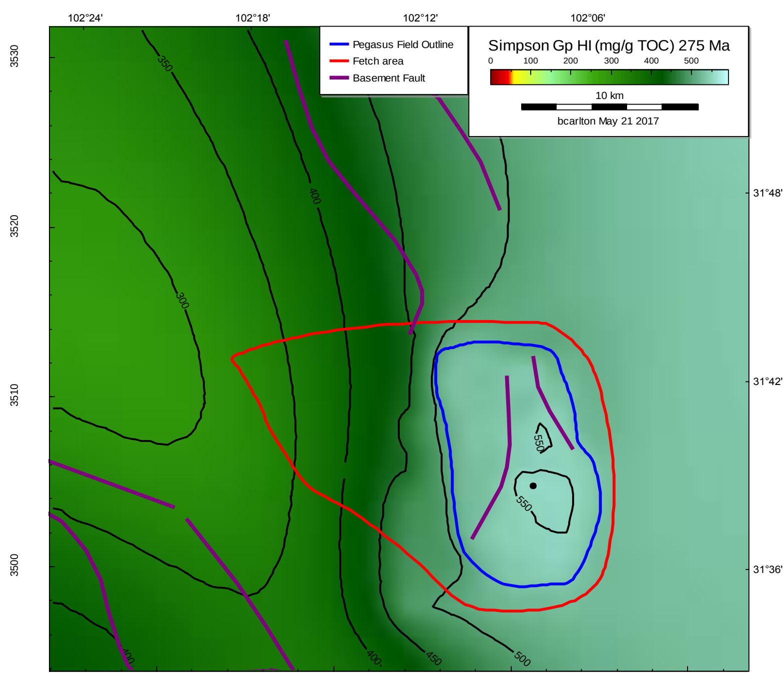

Figure A- 48. Simpson Group Hydrogen Index at 275 Ma for Working Hypothesis 3.

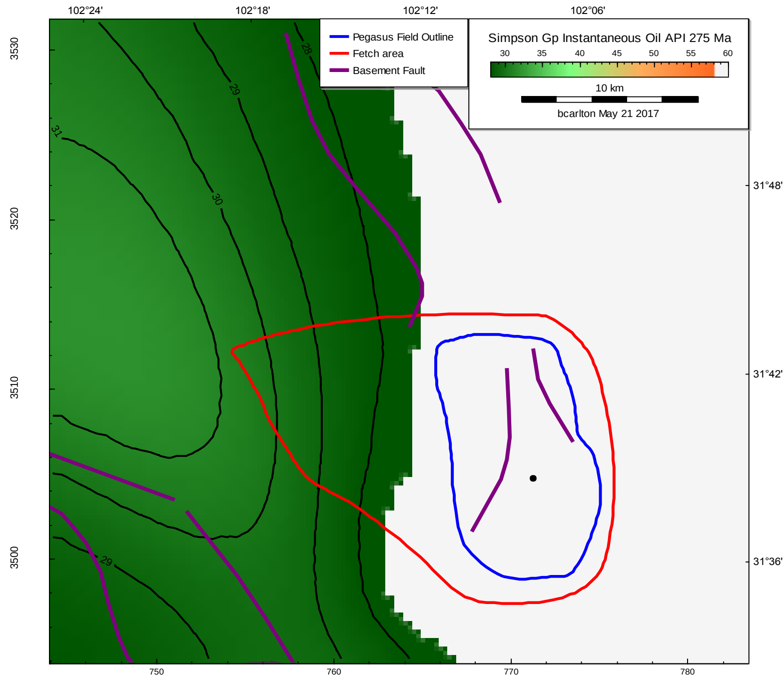

Figure A- 49. Simpson Group instantaneous oil API gravity at 275 Ma for Working Hypothesis 3.

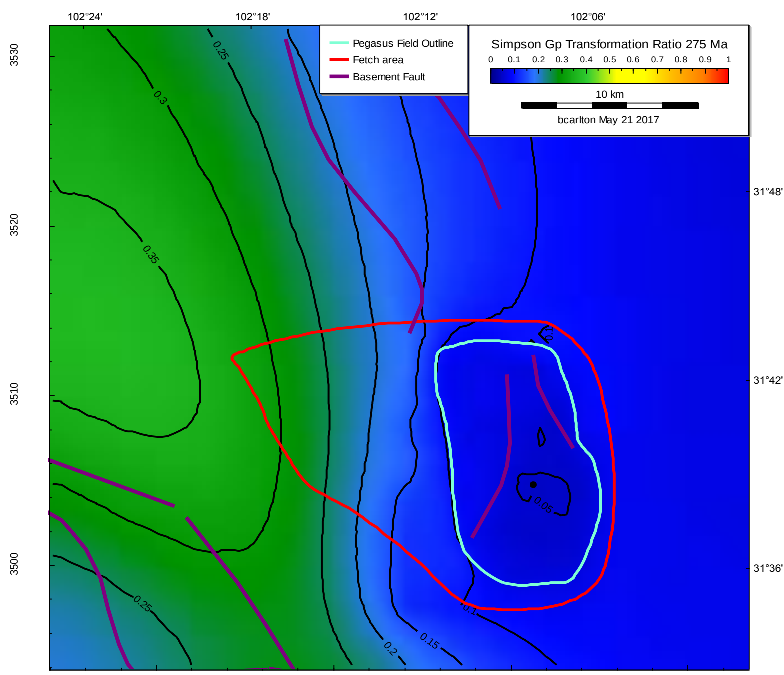

Figure A- 50. Simpson Group transformation ratio at 275 Ma for Working Hypothesis 3.

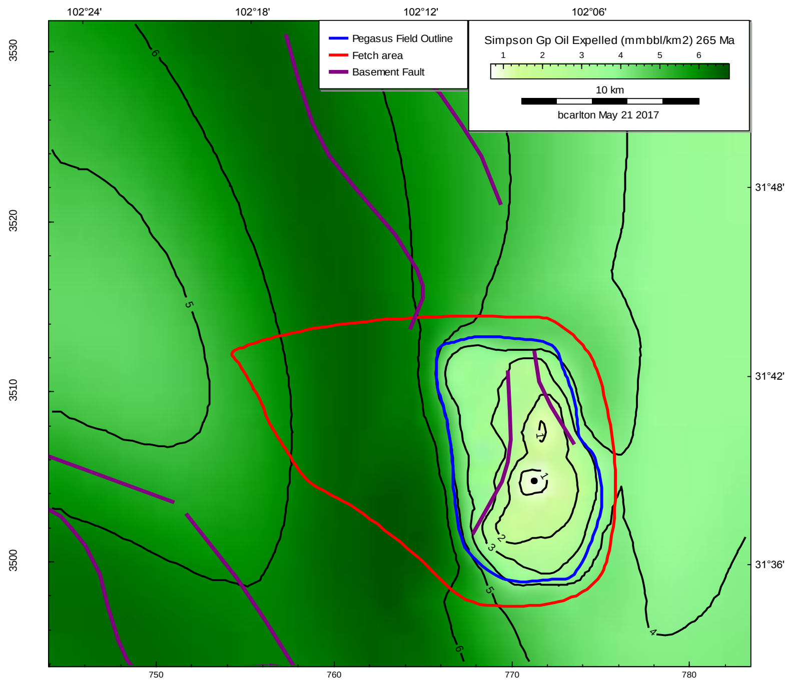

Figure A- 51. Oil Expelled from the Simpson Group at 265 Ma for Working Hypothesis 3.

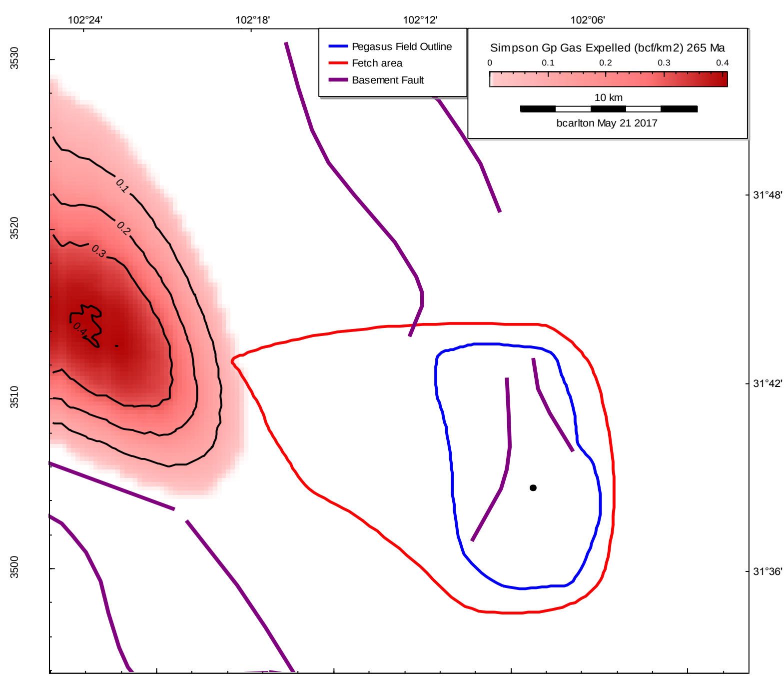

Figure A- 52. Gas Expelled from the Simpson Group at 265 Ma for Working Hypothesis 3.

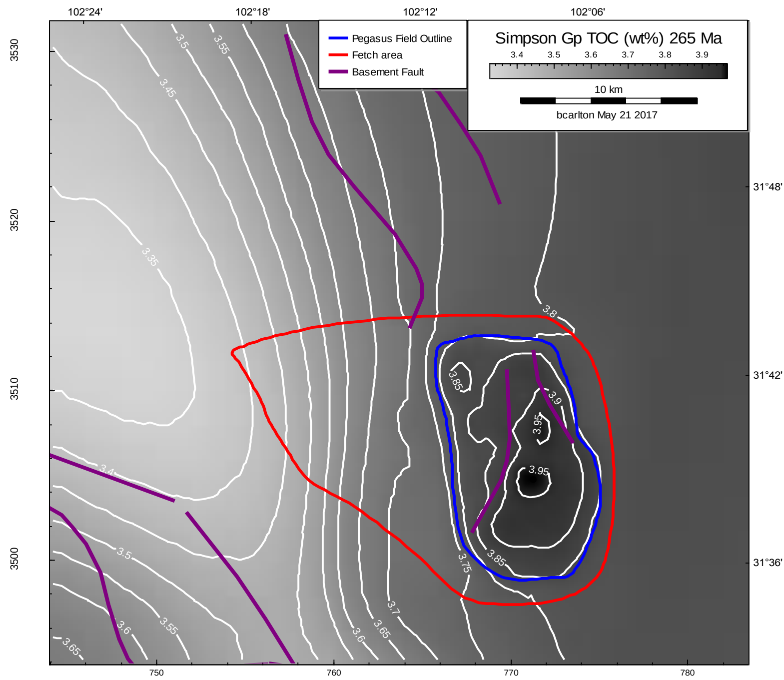

Figure A- 53. Simpson Group Total Organic Carbon at 265 Ma for Working Hypothesis 3.

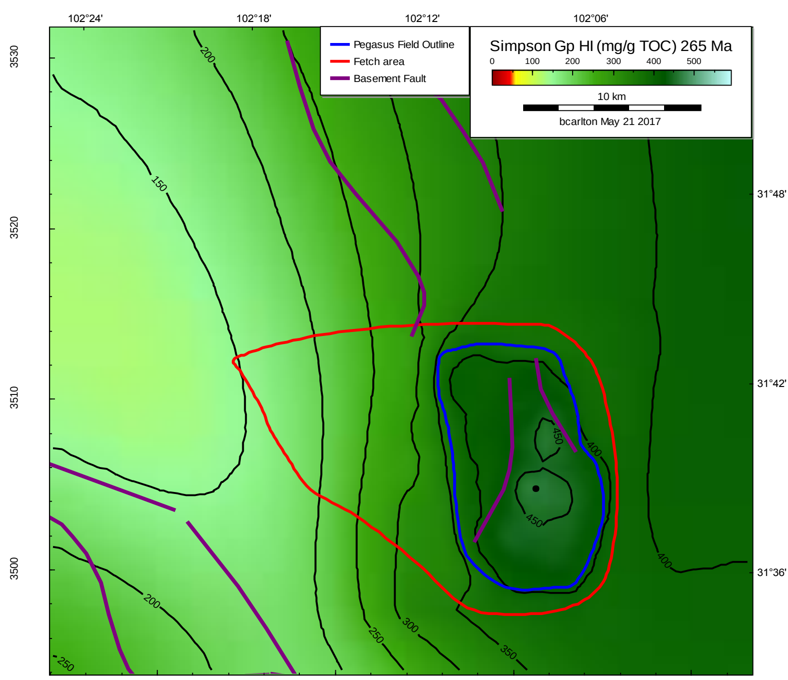

Figure A- 54. Simpson Group Hydrogen Index at 265 Ma for Working Hypothesis 3.

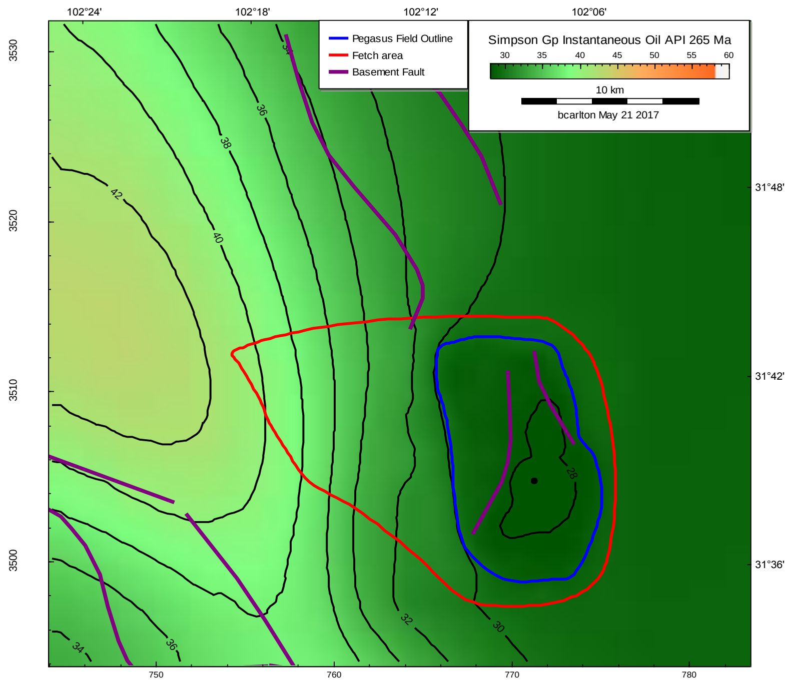

Figure A- 55. Simpson Group instantaneous oil API gravity at 265 Ma for Working Hypothesis 3.

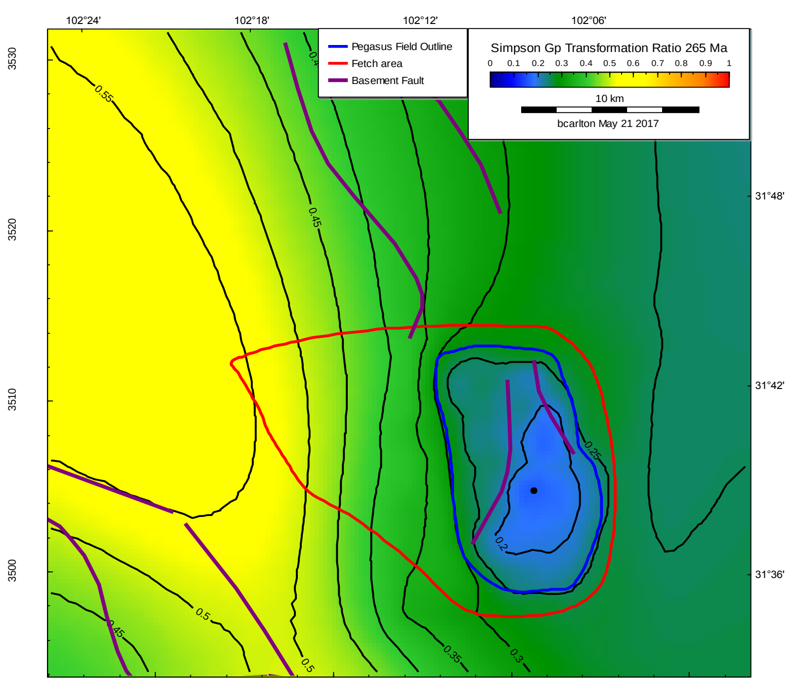

Figure A- 56. Simpson Group transformation ratio at 265 Ma for Working Hypothesis 3.

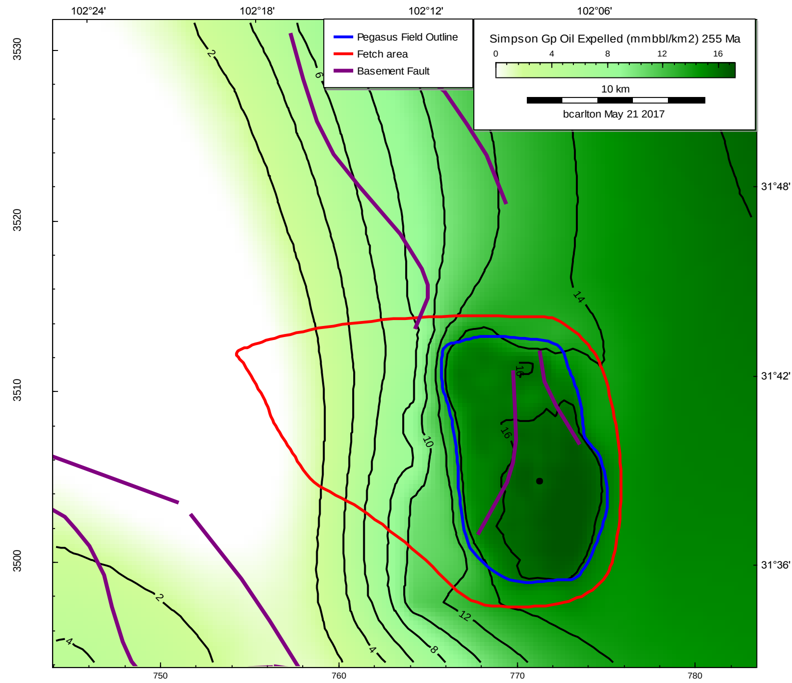

Figure A- 57. Oil Expelled from the Simpson Group at 255 Ma for Working Hypothesis 3.

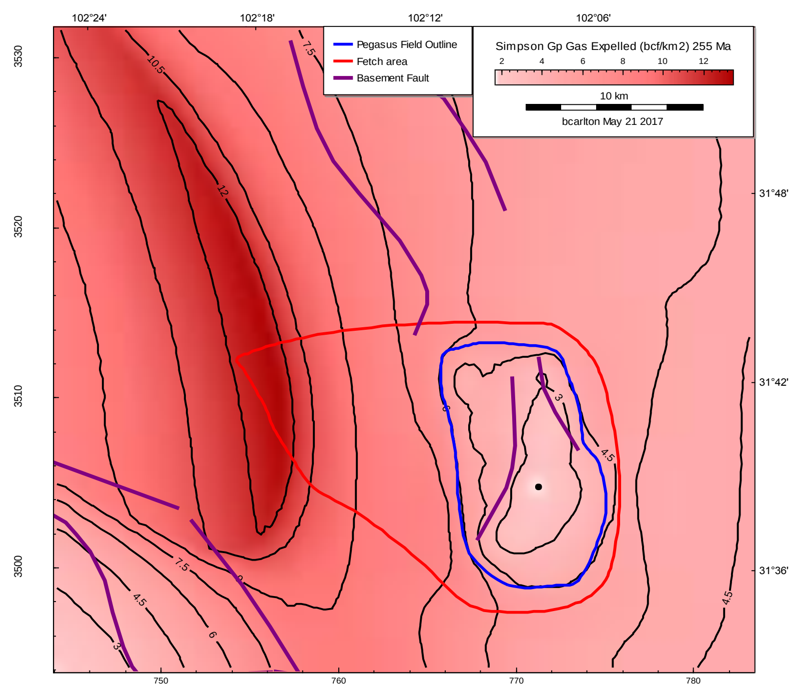

Figure A- 58. Gas Expelled from the Simpson Group at 255 Ma for Working Hypothesis 3.

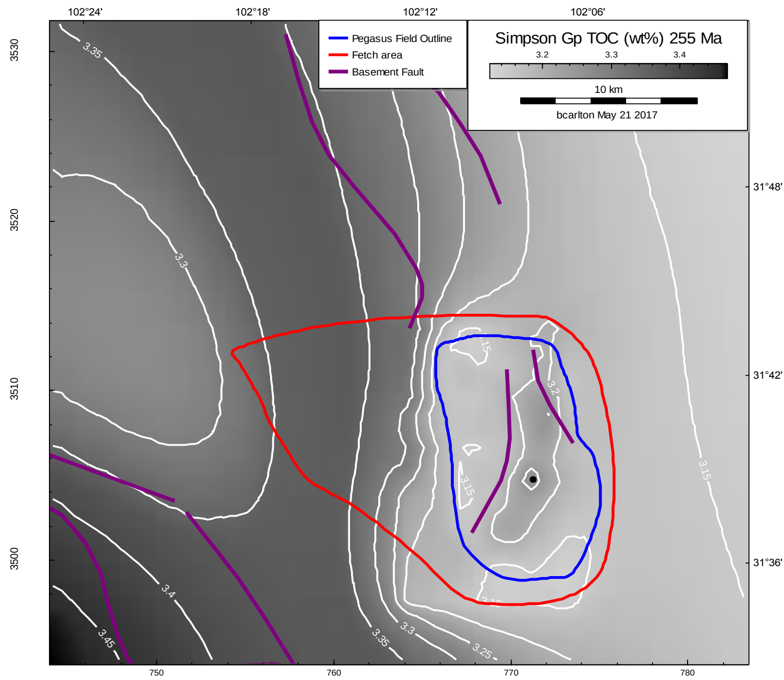

Figure A- 59. Simpson Group Total Organic Carbon at 255 Ma for Working Hypothesis 3.

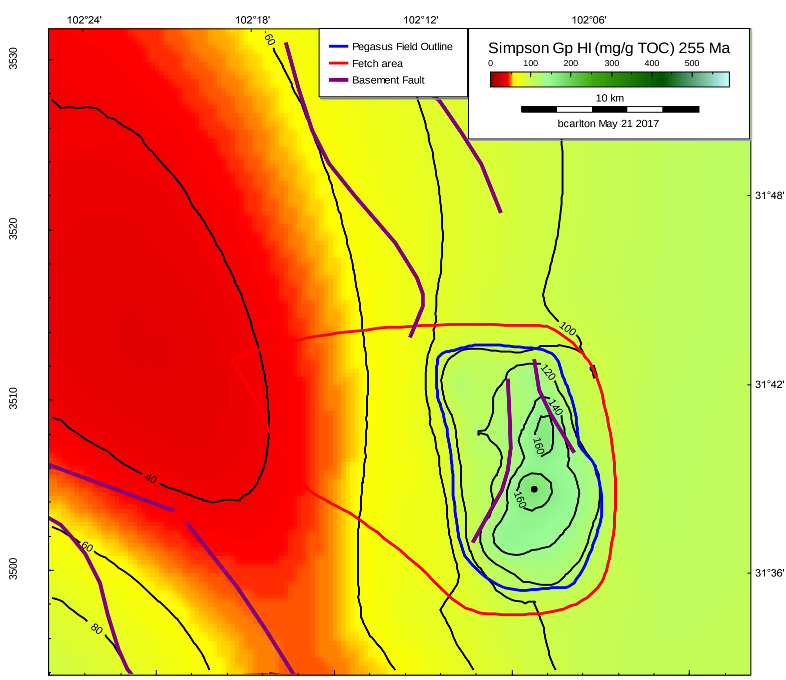

Figure A- 60. Simpson Group Hydrogen Index at 255 Ma for Working Hypothesis 3.

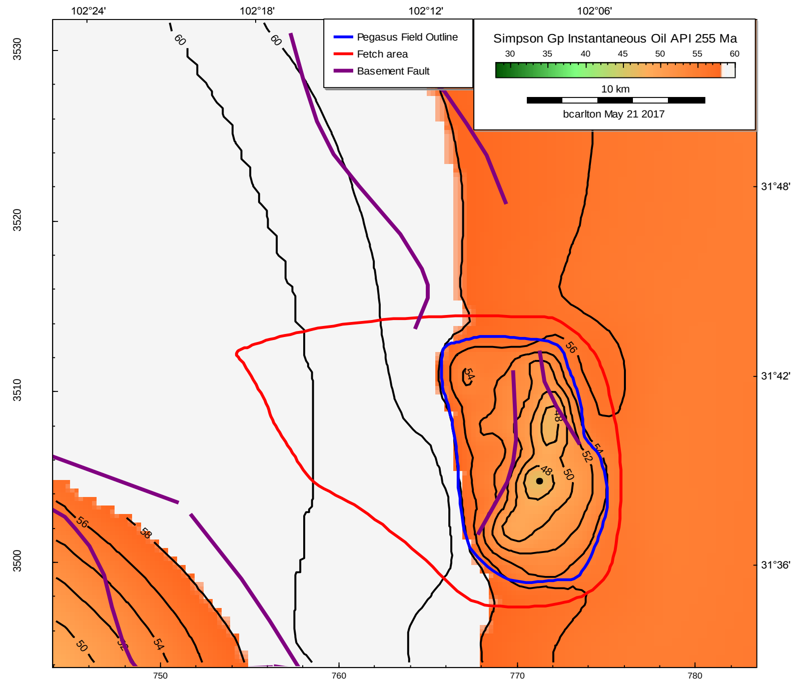

Figure A- 61. Simpson Group instantaneous oil API gravity at 255 Ma for Working Hypothesis 3.

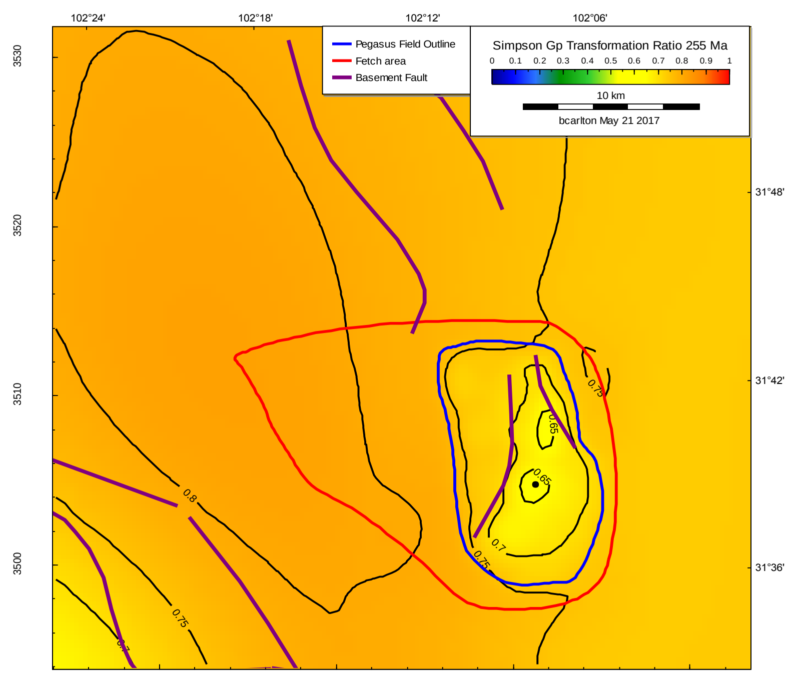

Figure A- 62. Simpson Group transformation ratio at 255 Ma for Working Hypothesis 3.

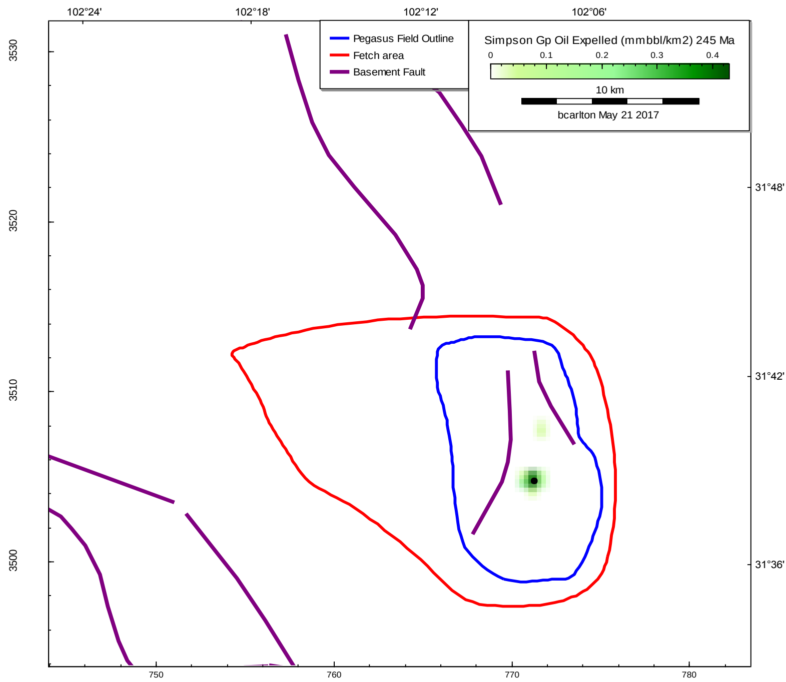

Figure A- 63. Oil Expelled from the Simpson Group at 245 Ma for Working Hypothesis 3.

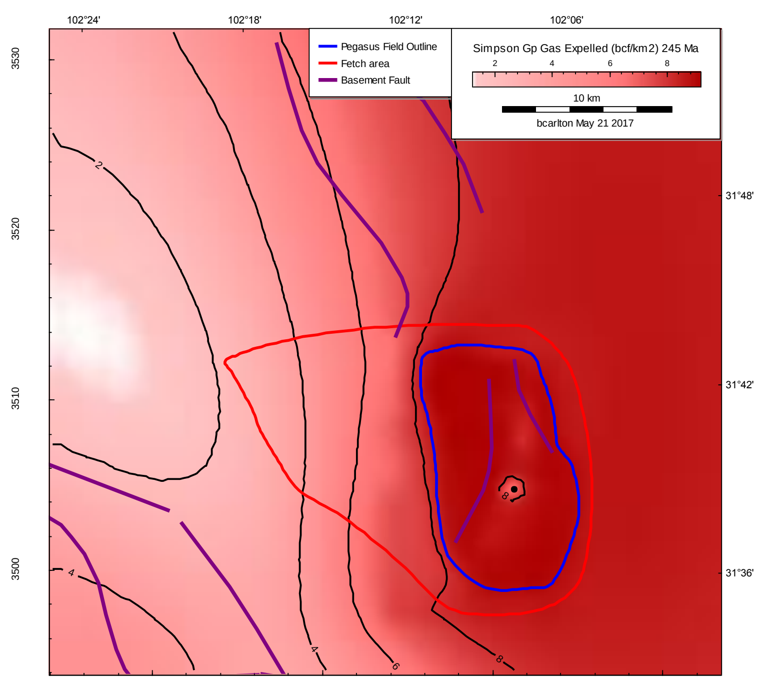

Figure A- 64. Gas Expelled from the Simpson Group at 245 Ma for Working Hypothesis 3.

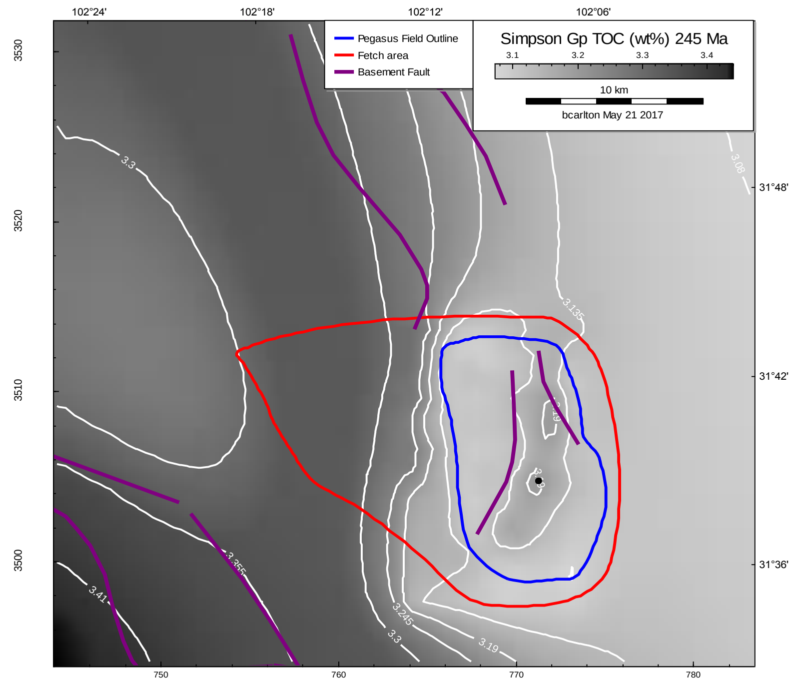

Figure A- 65. Simpson Group Total Organic Carbon at 245 Ma for Working Hypothesis 3.

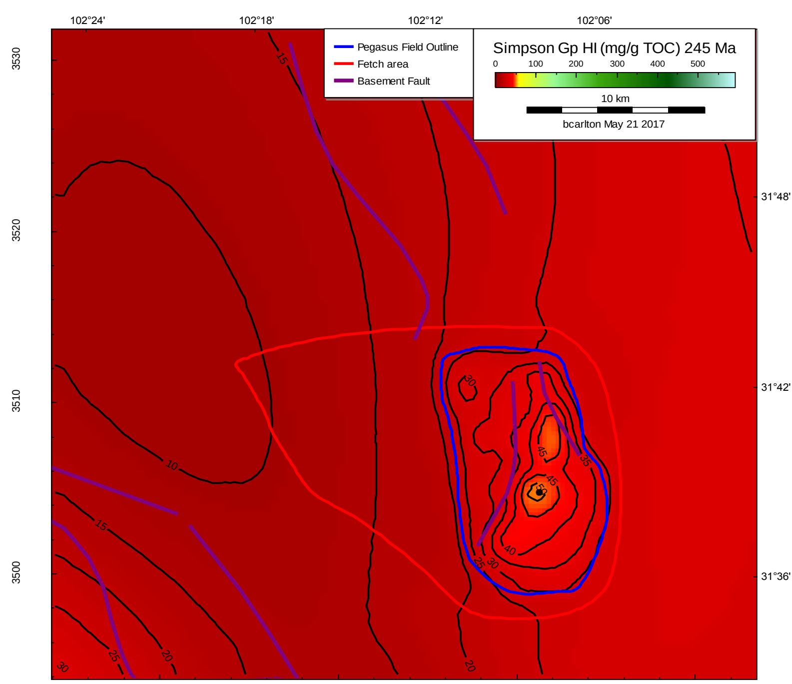

Figure A- 66. Simpson Group Hydrogen Index at 245 Ma for Working Hypothesis 3.

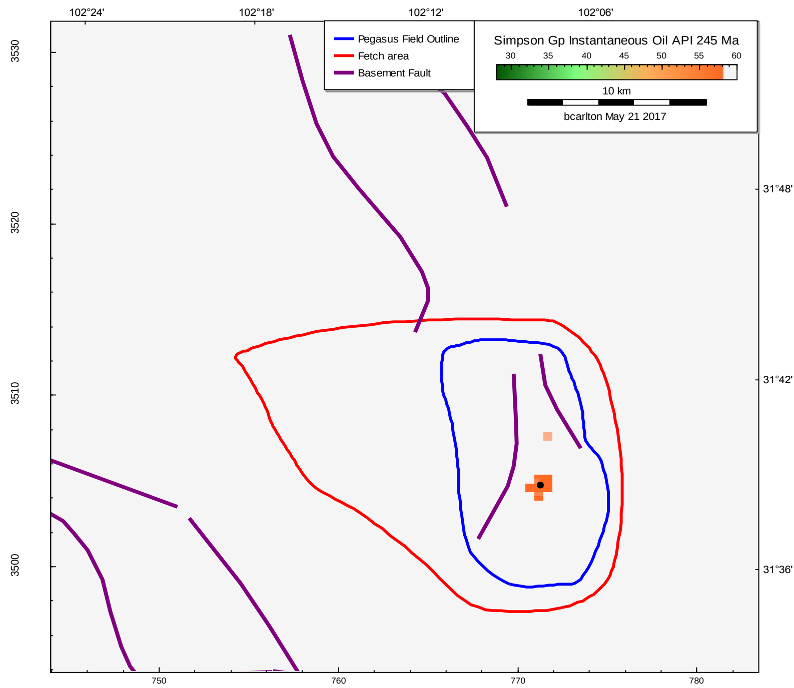

Figure A- 67. Simpson Group instantaneous oil API gravity at 245 Ma for Working Hypothesis 3.

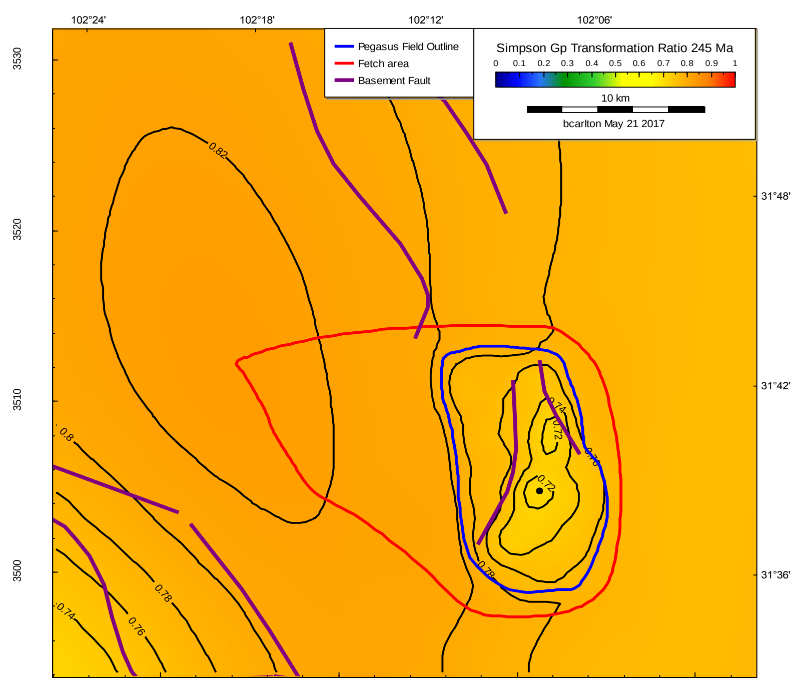

Figure A- 68. Simpson Group transformation ratio at 245 Ma for Working Hypothesis 3.

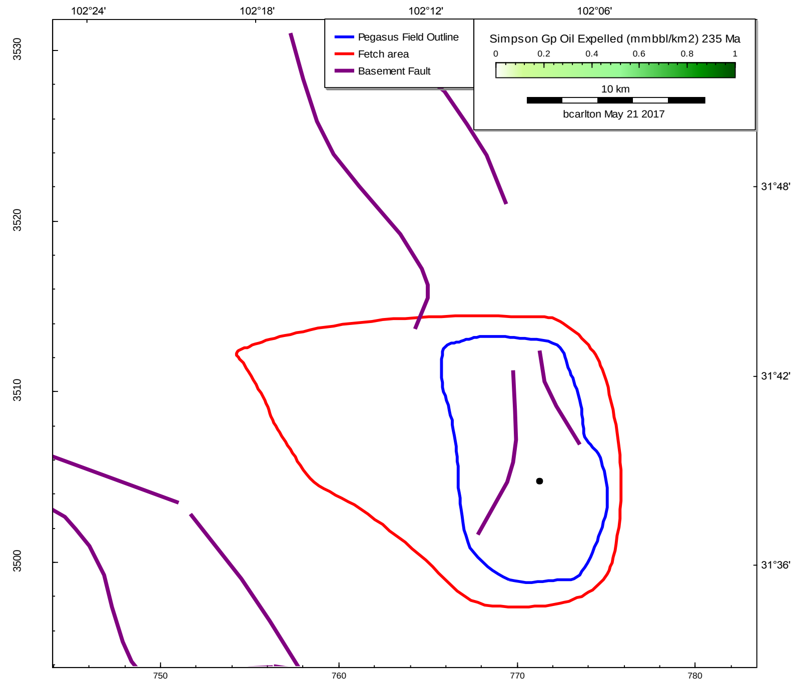

Figure A- 69. Oil Expelled from the Simpson Group at 235 Ma for Working Hypothesis 3.

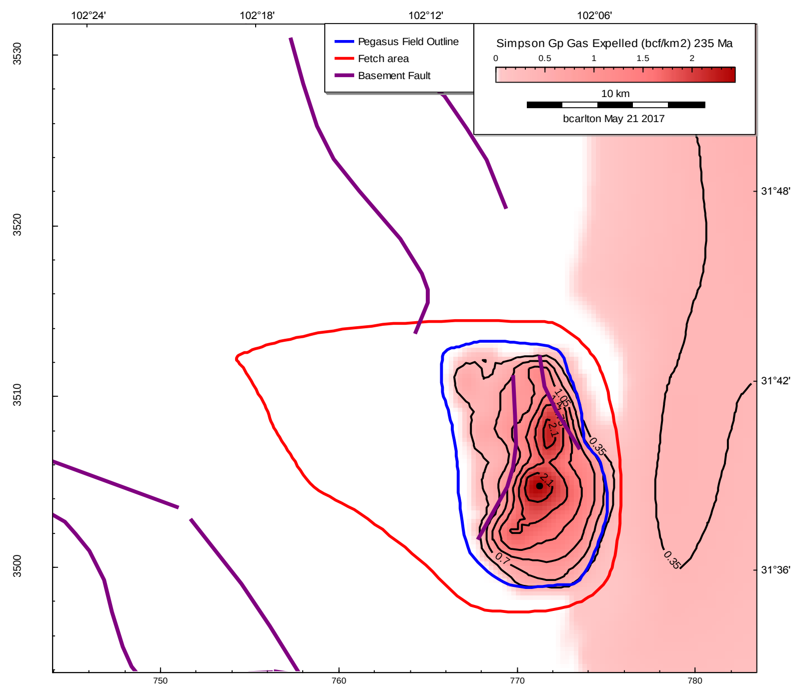

Figure A- 70. Gas Expelled from the Simpson Group at 235 Ma for Working Hypothesis 3.

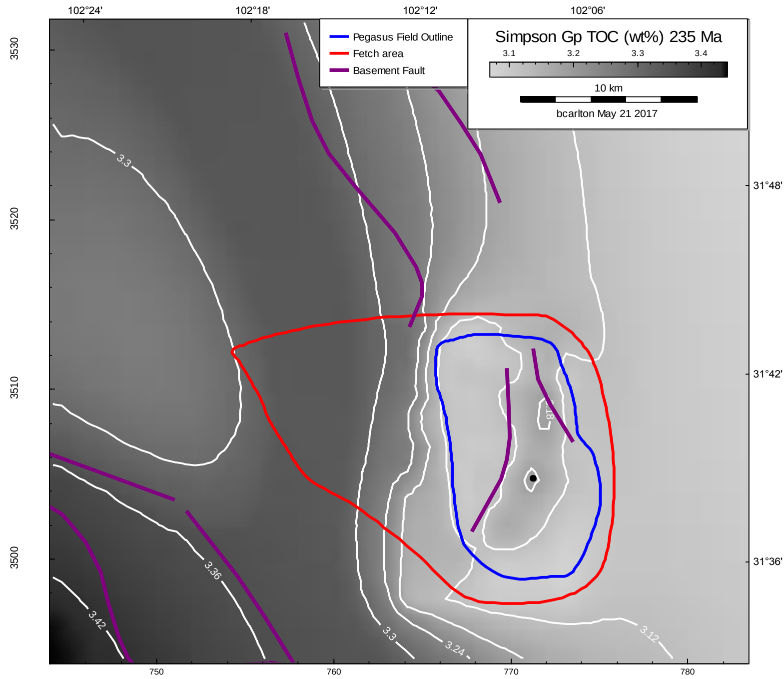

Figure A- 71. Simpson Group Total Organic Carbon at 235 Ma for Working Hypothesis 3.

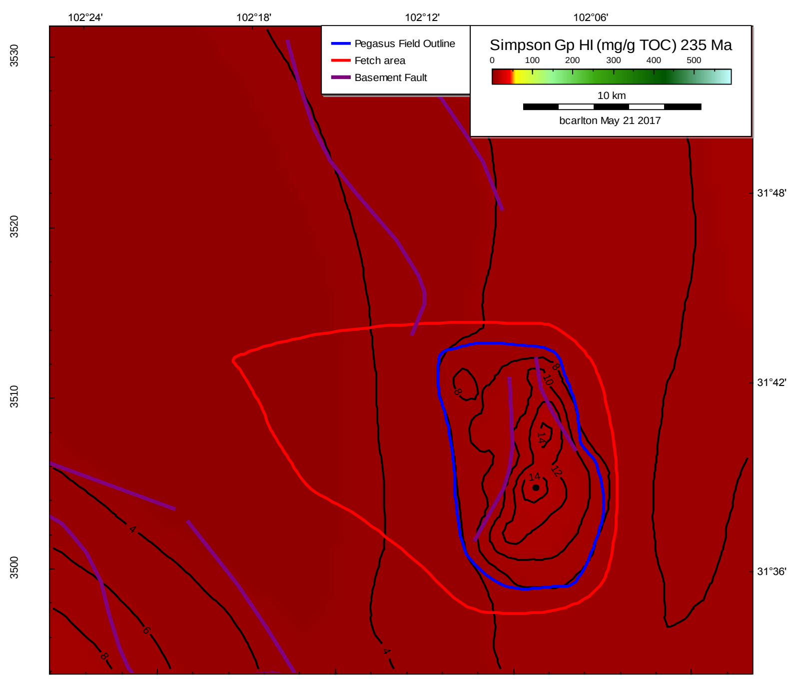

Figure A- 72. Simpson Group Hydrogen Index at 235 Ma for Working Hypothesis 3.

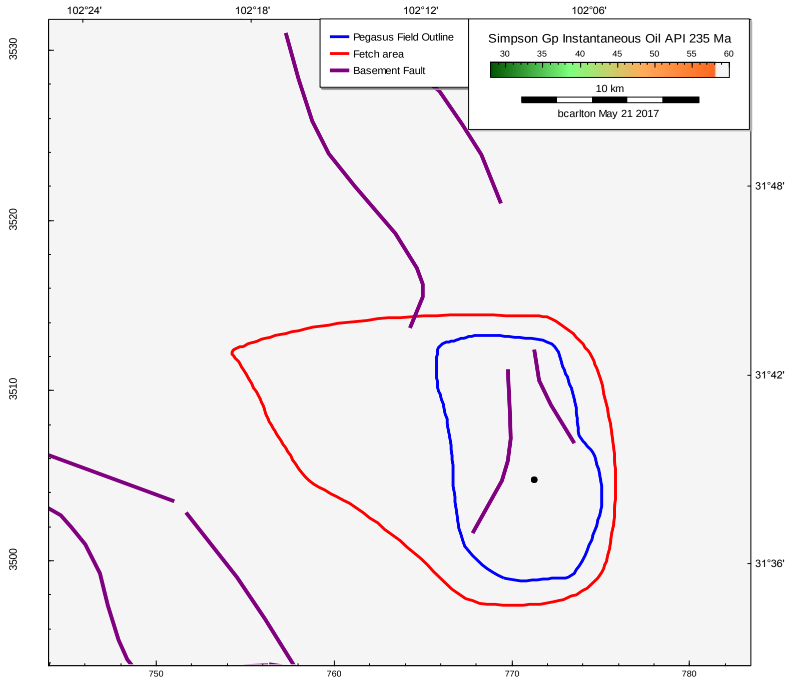

Figure A- 73. Simpson Group instantaneous oil API gravity at 235 Ma for Working Hypothesis 3.

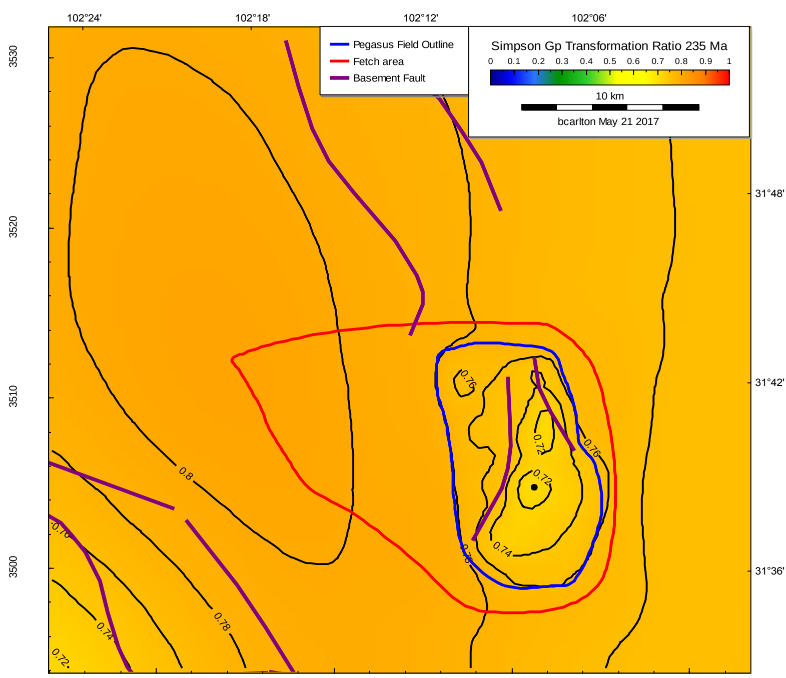

Figure A- 74. Simpson Group transformation ratio at 235 Ma for Working Hypothesis 3.

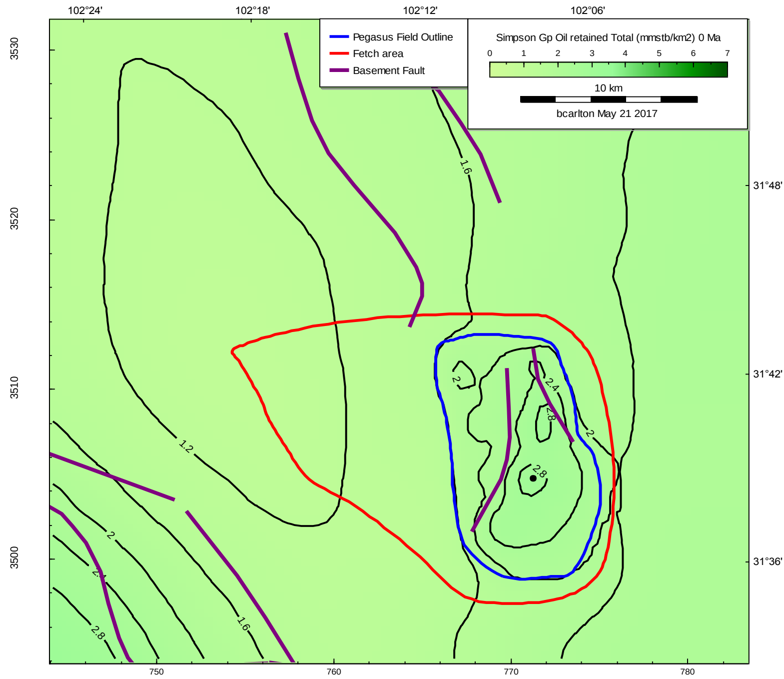

Figure A- 75. Simpson Group total oil retained at 0 Ma for Working Hypothesis 3.

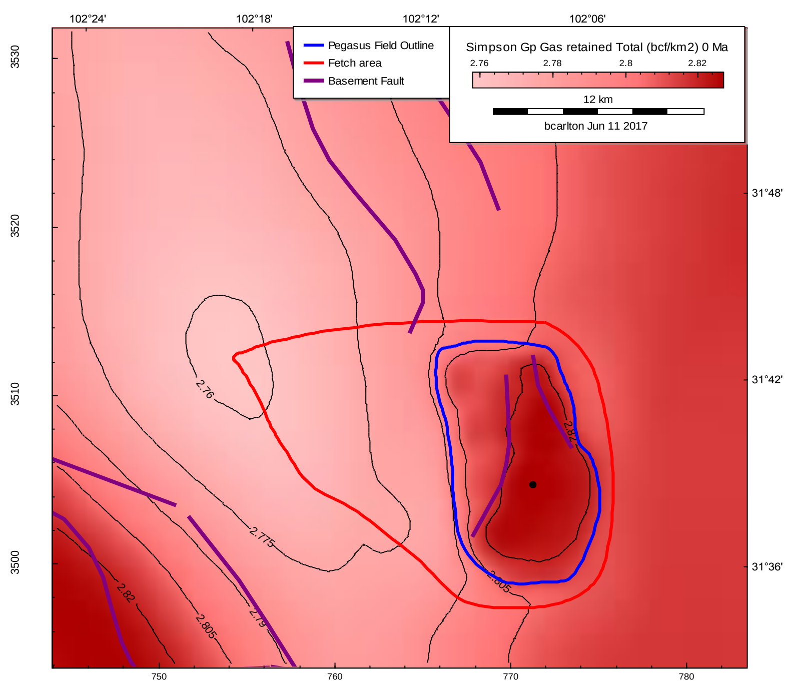

Figure A- 76. Simpson Group total gas retained at 0 Ma for Working Hypothesis 3.

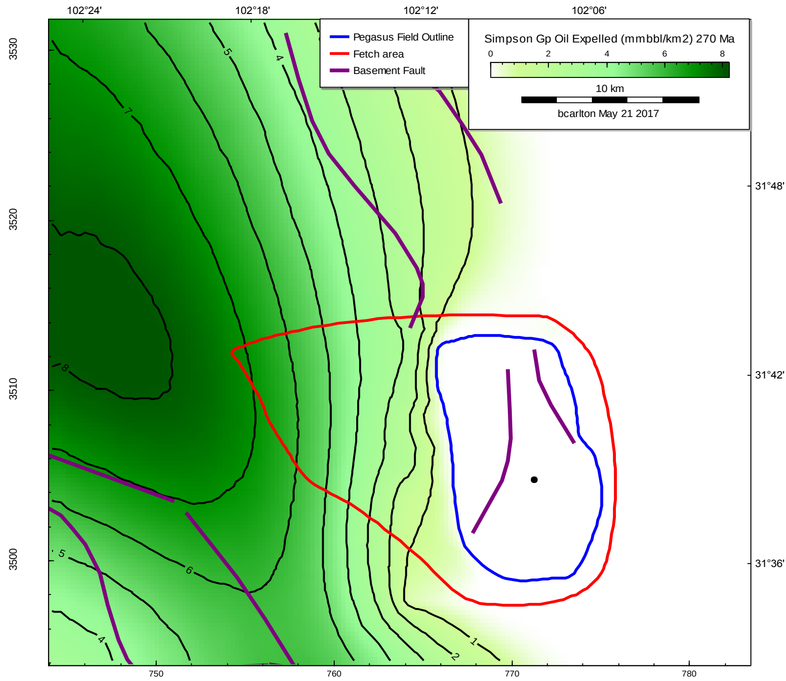

Figure A- 77. Oil Expelled from the Simpson Group at 270 Ma for Working Hypothesis 4.

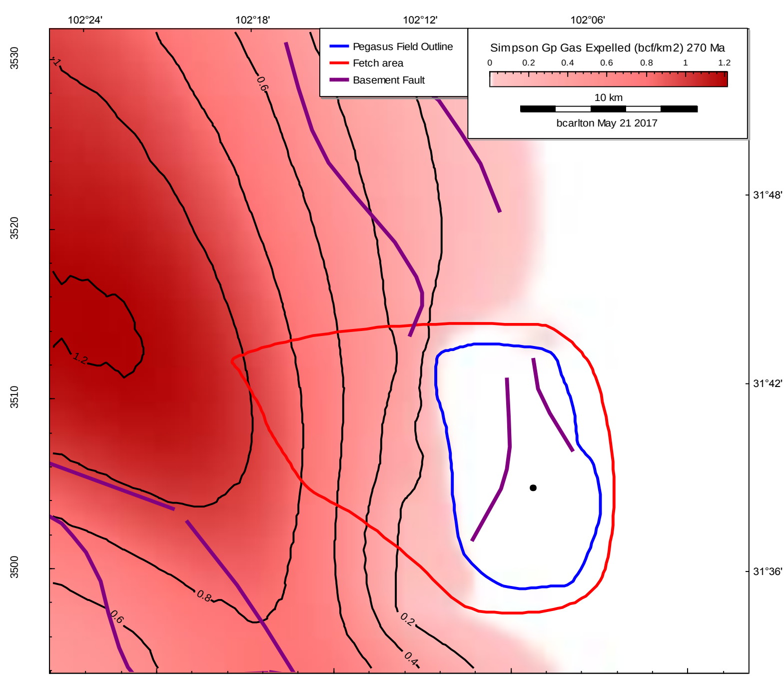

Figure A- 78. Gas Expelled from the Simpson Group at 270 Ma for Working Hypothesis 4.

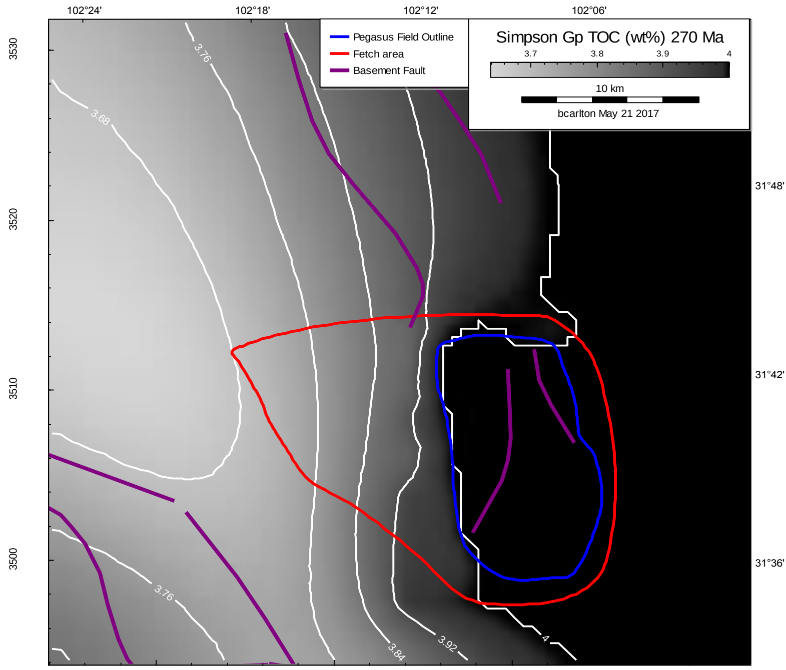

Figure A- 79. Simpson Group Total Organic Carbon at 270 Ma for Working Hypothesis 4.

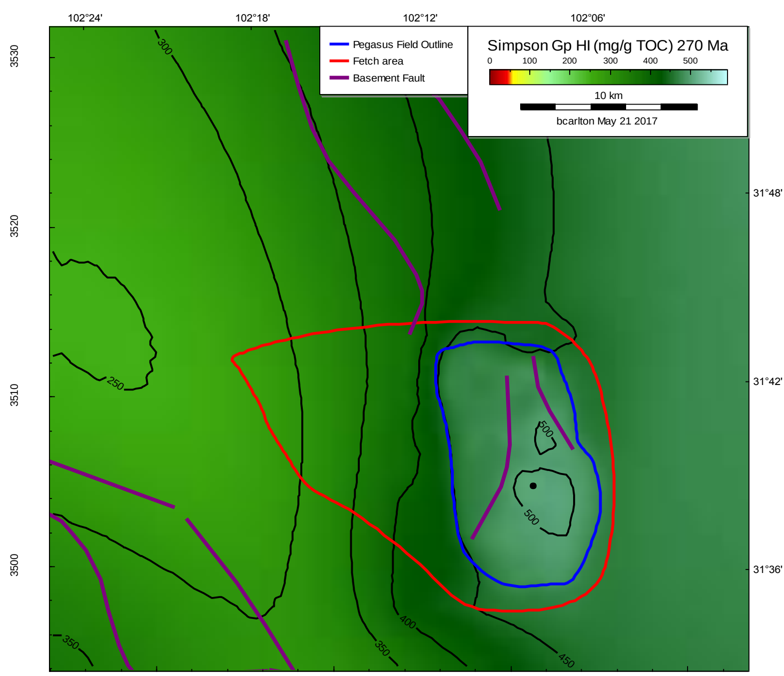

Figure A- 80. Simpson Group Hydrogen Index at 270 Ma for Working Hypothesis 4.

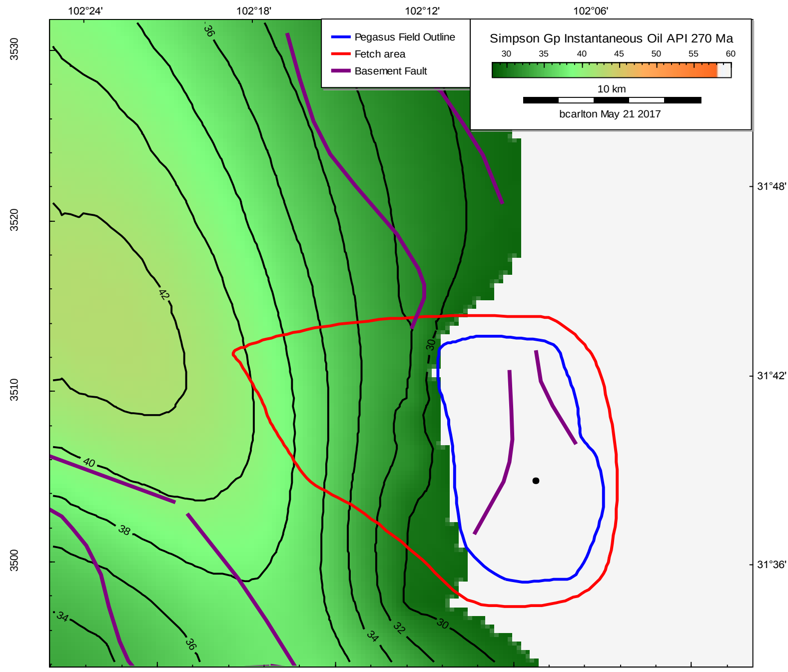

Figure A- 81. Simpson Group instantaneous oil API gravity at 270 Ma for Working Hypothesis 4.

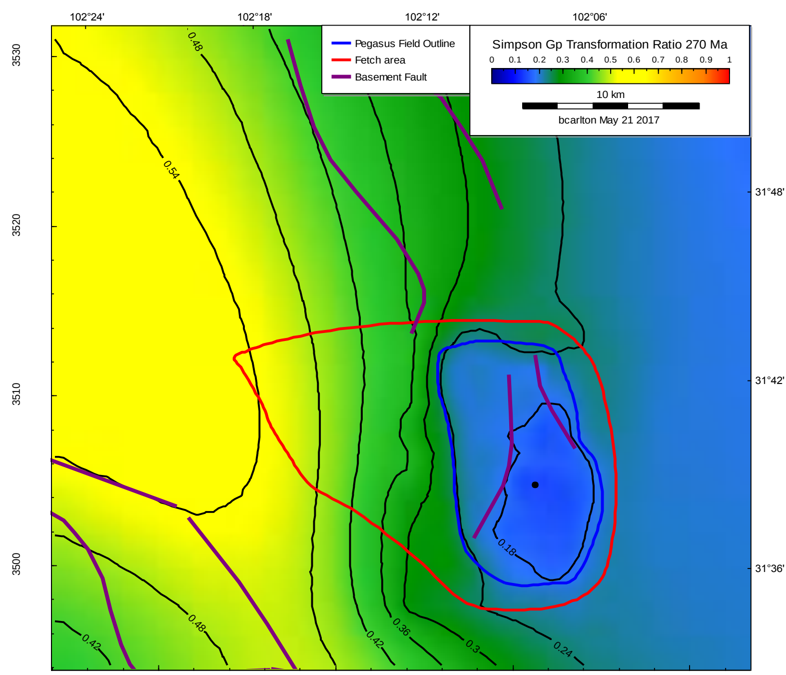

Figure A- 82. Simpson Group transformation ratio at 270 Ma for Working Hypothesis 4.

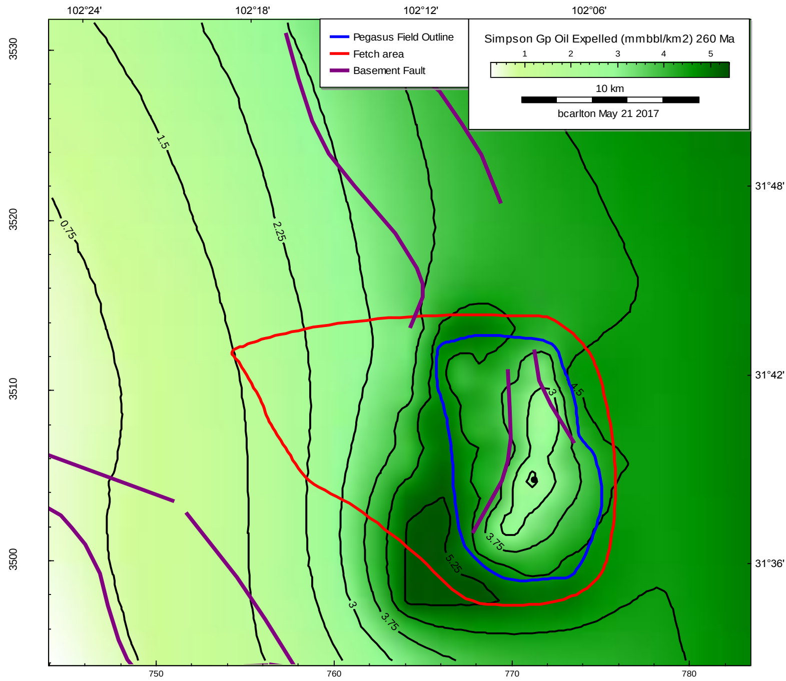

Figure A- 83. Oil Expelled from the Simpson Group at 260 Ma for Working Hypothesis 4.

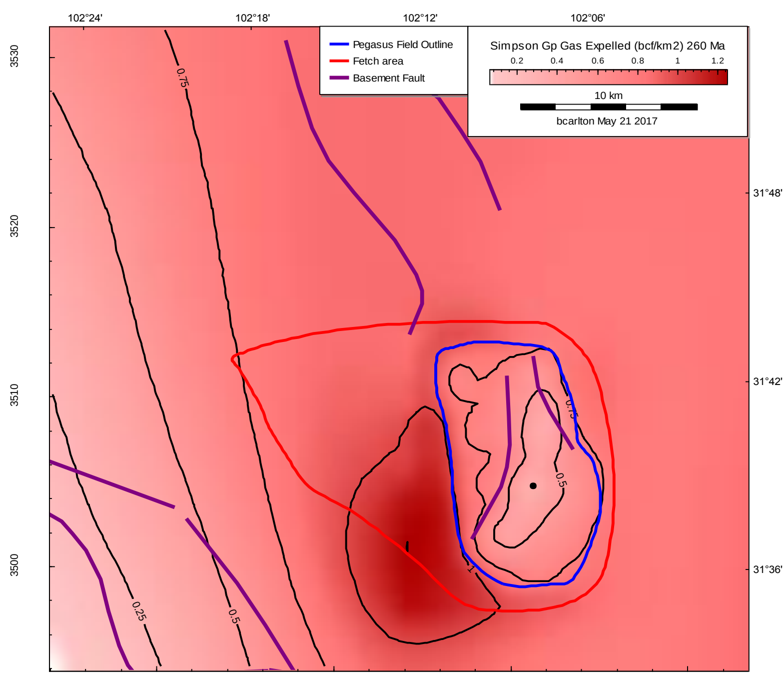

Figure A- 84. Gas Expelled from the Simpson Group at 260 Ma for Working Hypothesis 4.

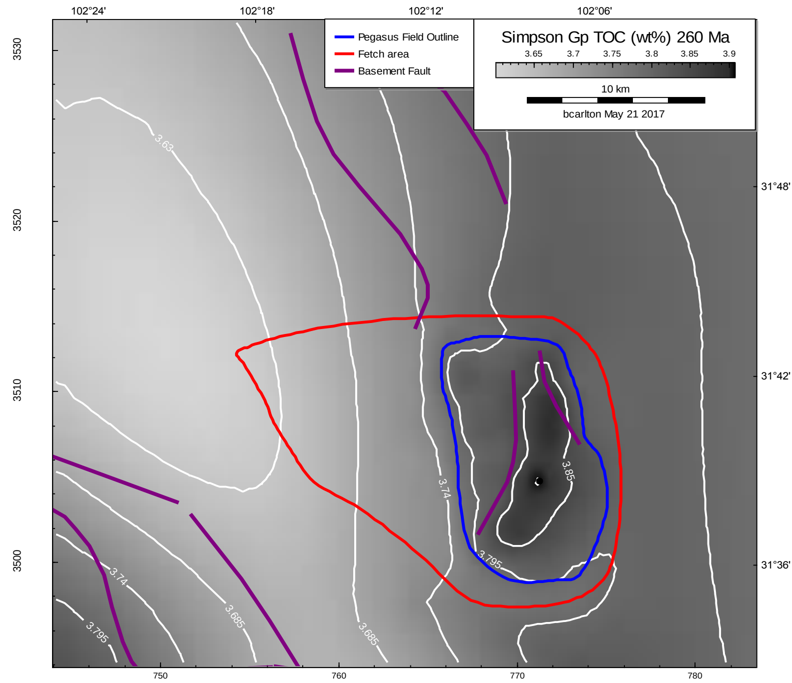

Figure A- 85. Simpson Group Total Organic Carbon at 260 Ma for Working Hypothesis 4.

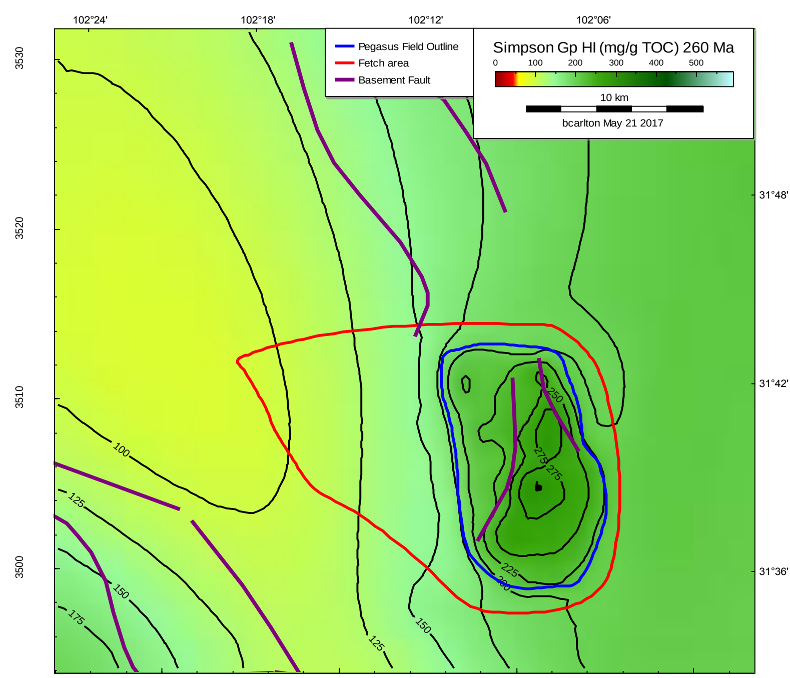

Figure A- 86. Simpson Group Hydrogen Index at 260 Ma for Working Hypothesis 4.

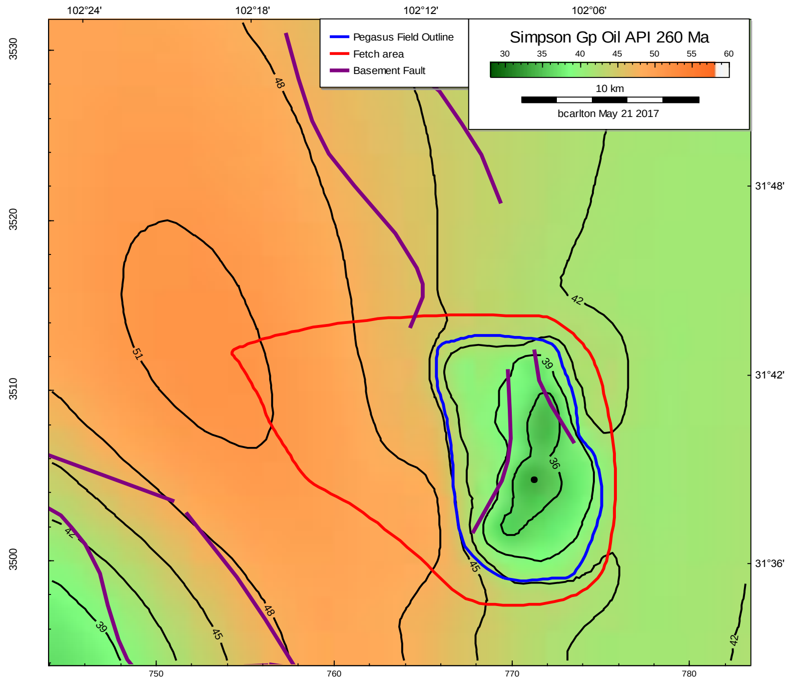

Figure A- 87. Simpson Group instantaneous oil API gravity at 260 Ma for Working Hypothesis 4.

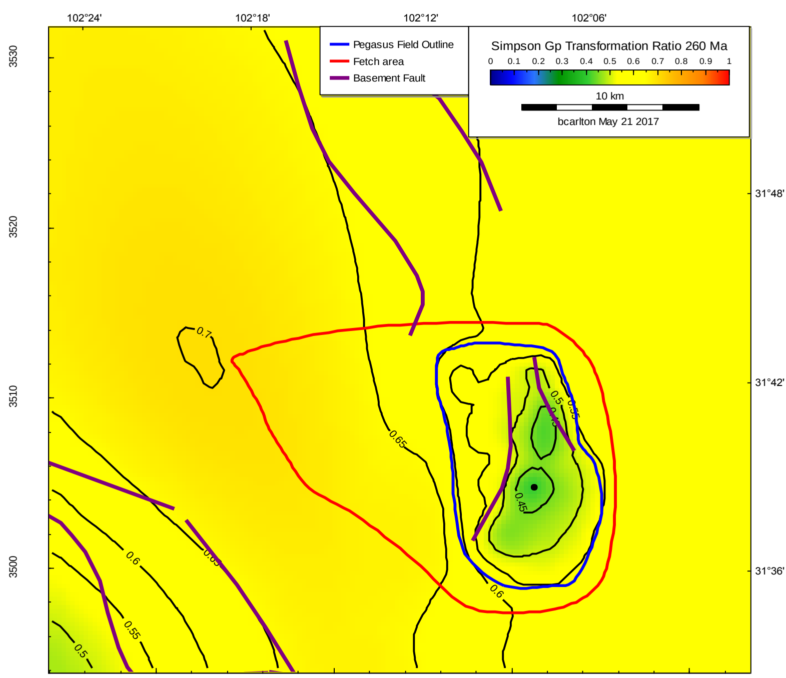

Figure A- 88. Simpson Group transformation ratio at 260 Ma for Working Hypothesis 4.

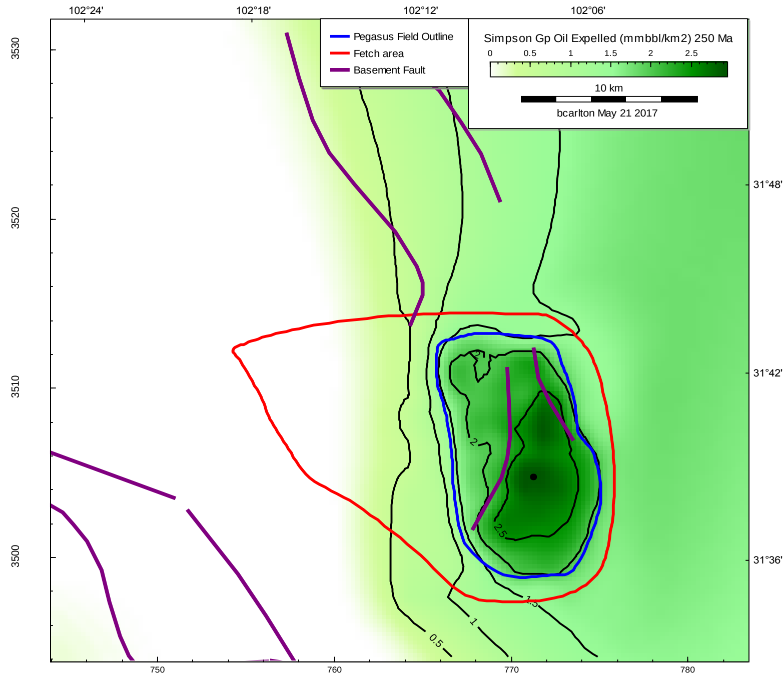

Figure A- 89. Oil Expelled from the Simpson Group at 250 Ma for Working Hypothesis 4.

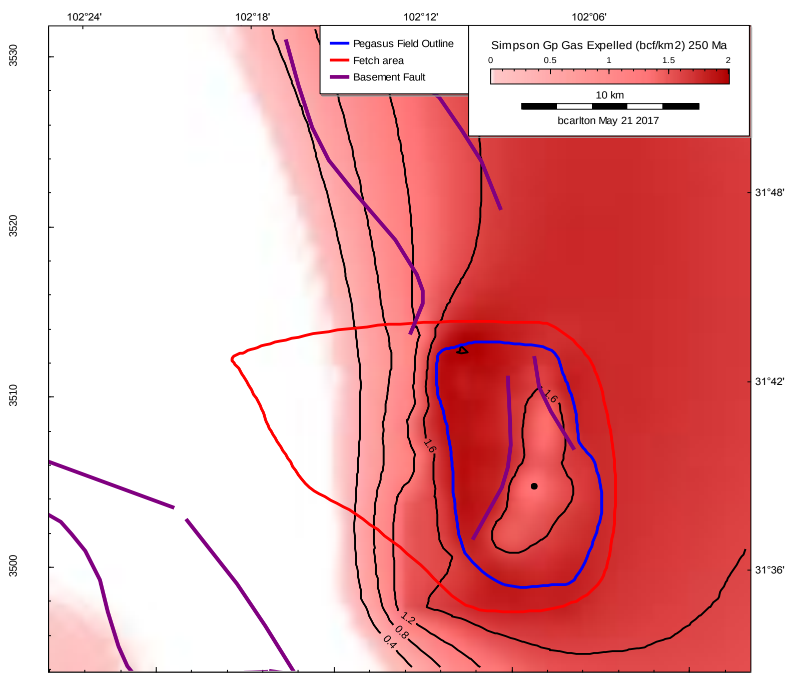

Figure A- 90. Gas Expelled from the Simpson Group at 250 Ma for Working Hypothesis 3.

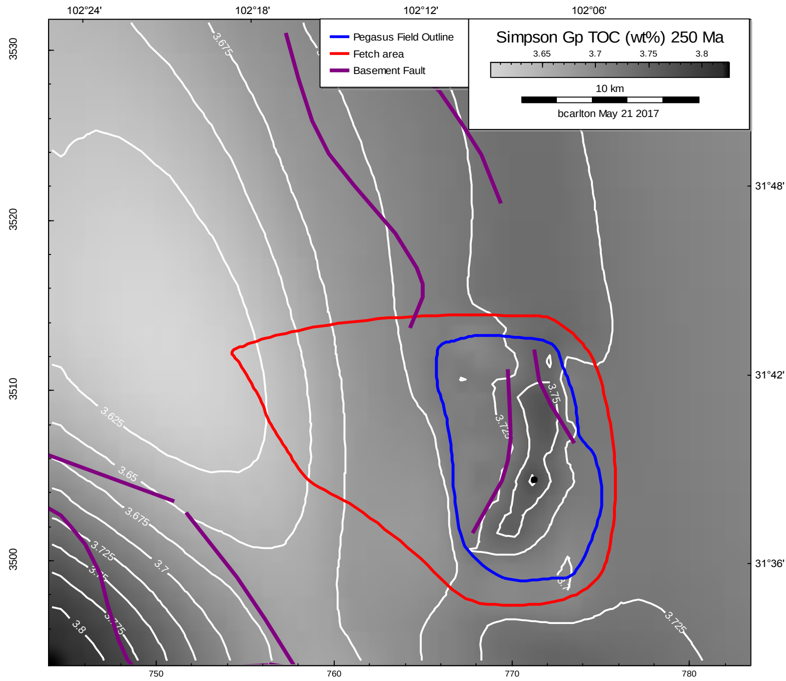

Figure A- 91. Simpson Group Total Organic Carbon at 250 Ma for Working Hypothesis 4.

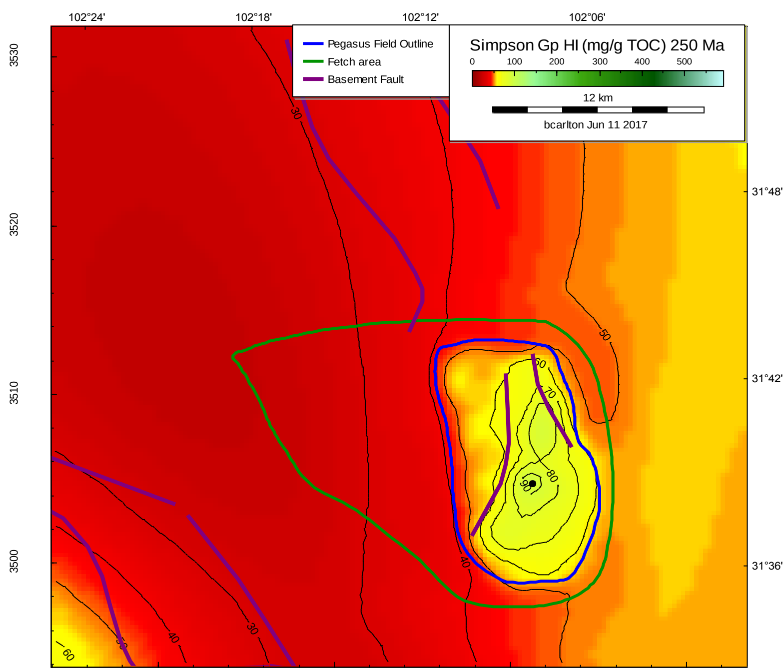

Figure A- 92. Simpson Group Hydrogen Index at 250 Ma for Working Hypothesis 4.

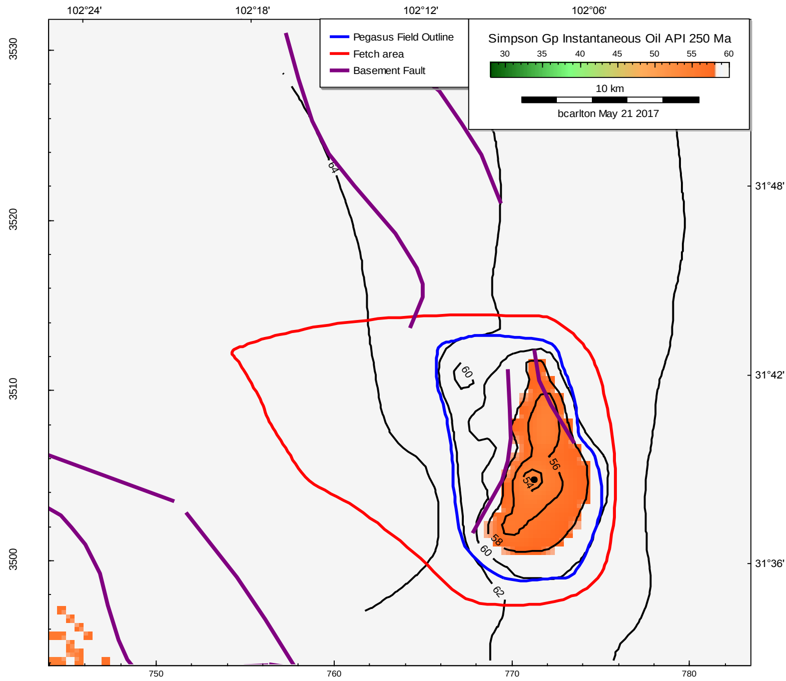

Figure A- 93. Simpson Group instantaneous oil API gravity at 250 Ma for Working Hypothesis 4.

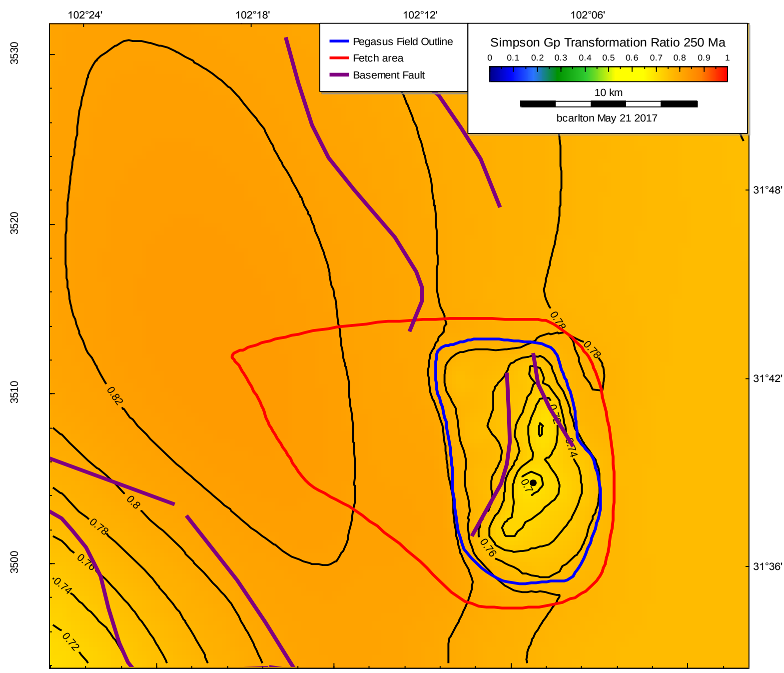

Figure A- 94. Simpson Group transformation ratio at 285 Ma for Working Hypothesis 4.

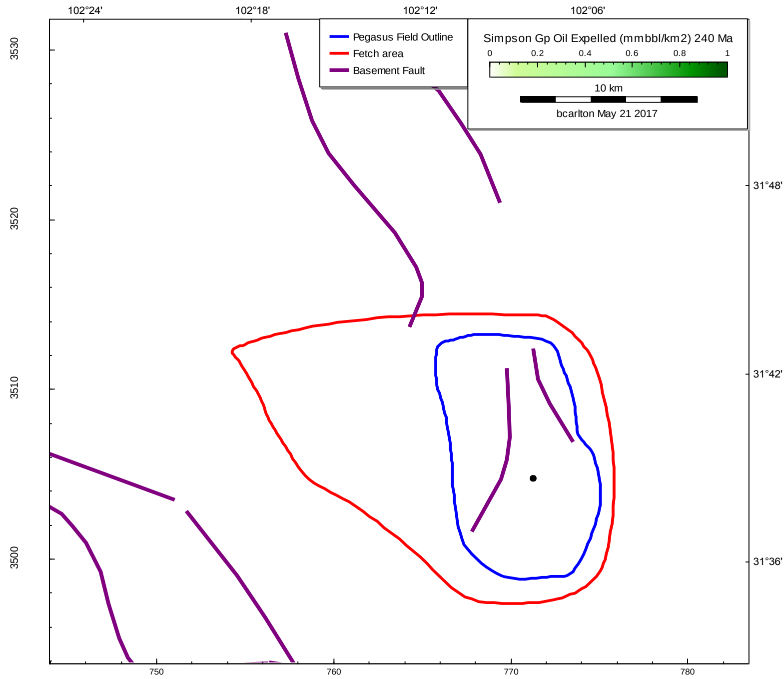

Figure A- 95. Oil Expelled from the Simpson Group at 240 Ma for Working Hypothesis 4.

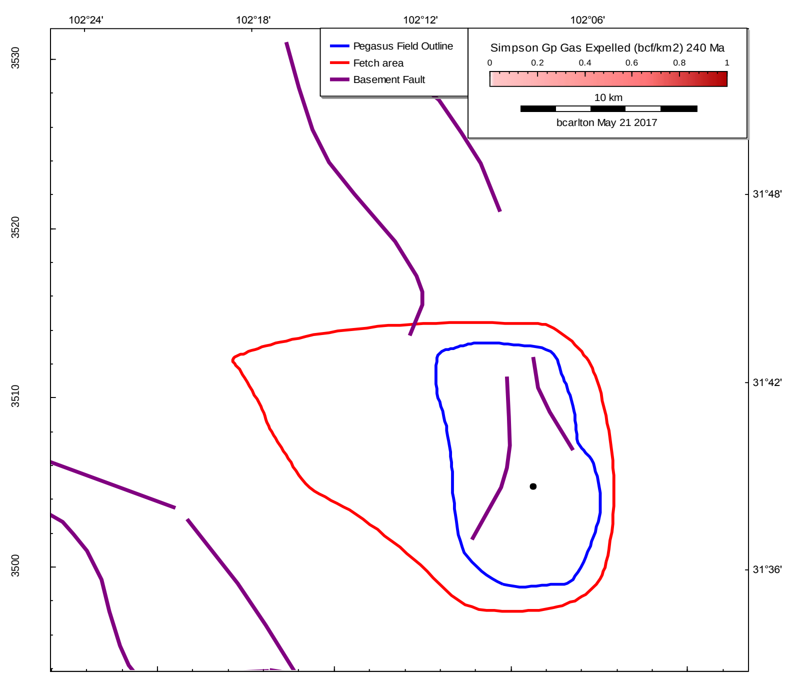

Figure A- 96 Gas expelled from the Simpson Group at 240 Ma for Working Hypothesis 4.

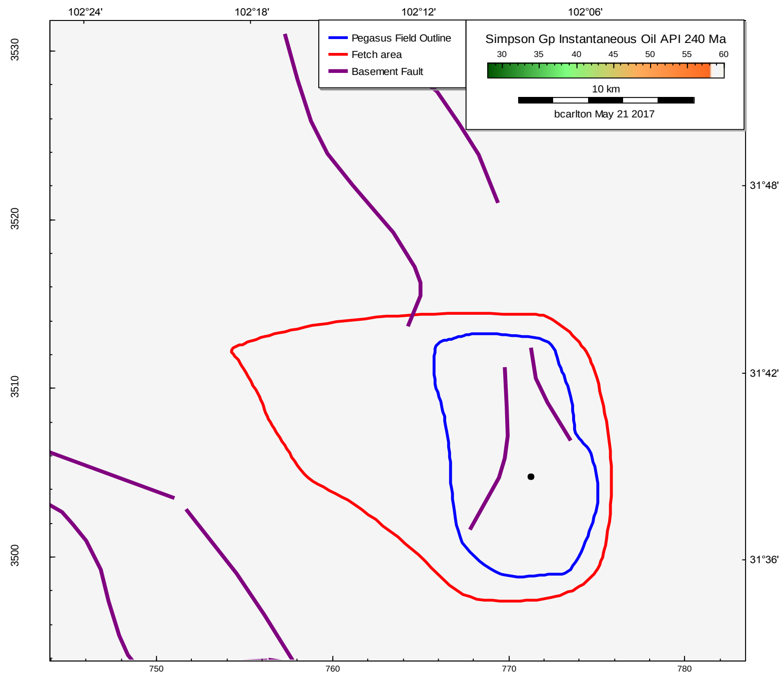

Figure A- 97. Simpson Group instantaneous oil API gravity at 240 Ma for Working Hypothesis 4.

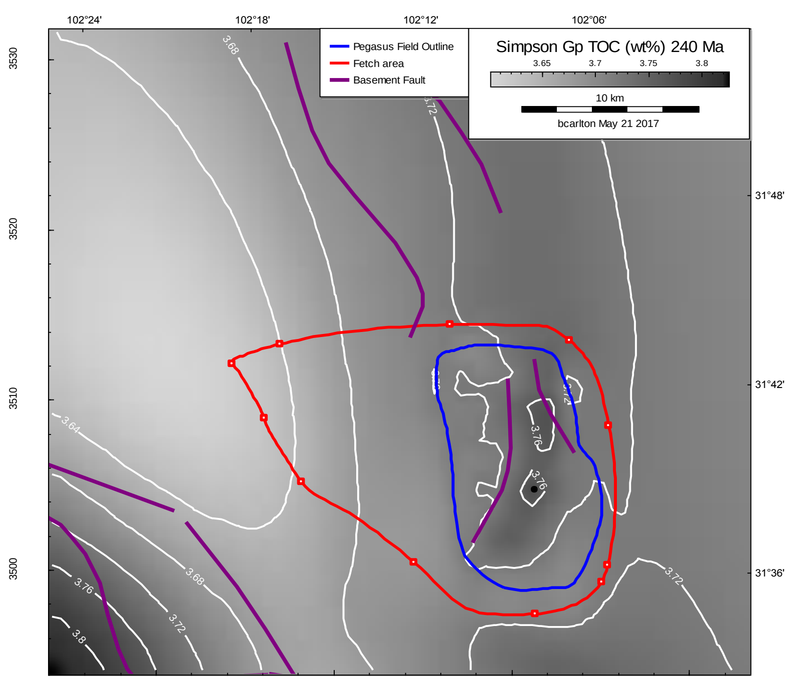

Figure A- 98. Simpson Group Total Organic Carbon at 240 Ma for Working Hypothesis 4.

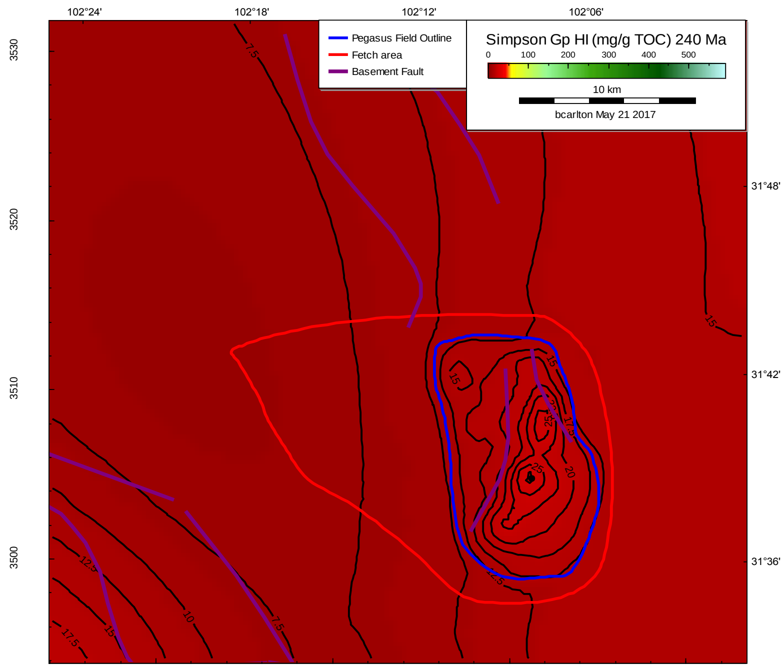

Figure A- 99. Simpson Group Hydrogen Index at 240 Ma for Working Hypothesis 4.

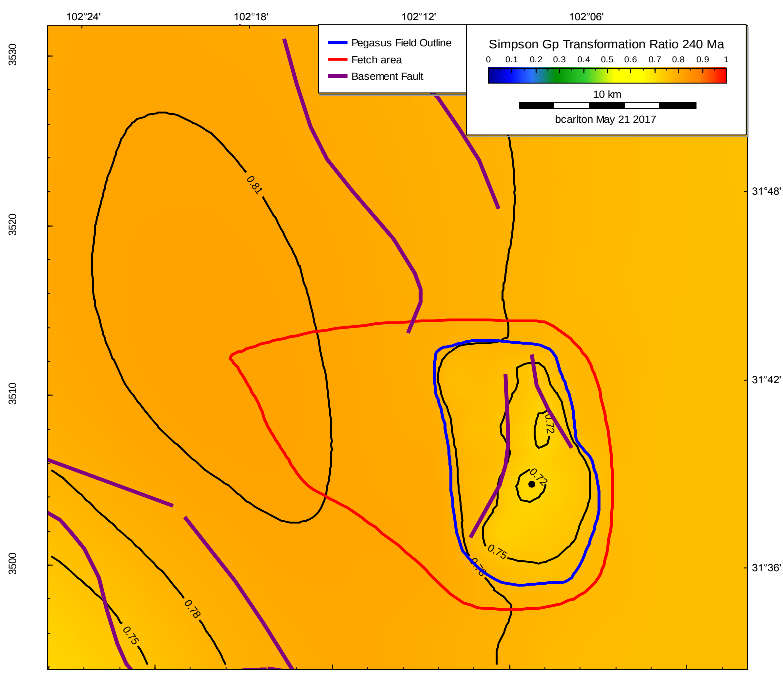

Figure A- 100. Simpson Group transformation ratio at 240 Ma for Working Hypothesis 4.

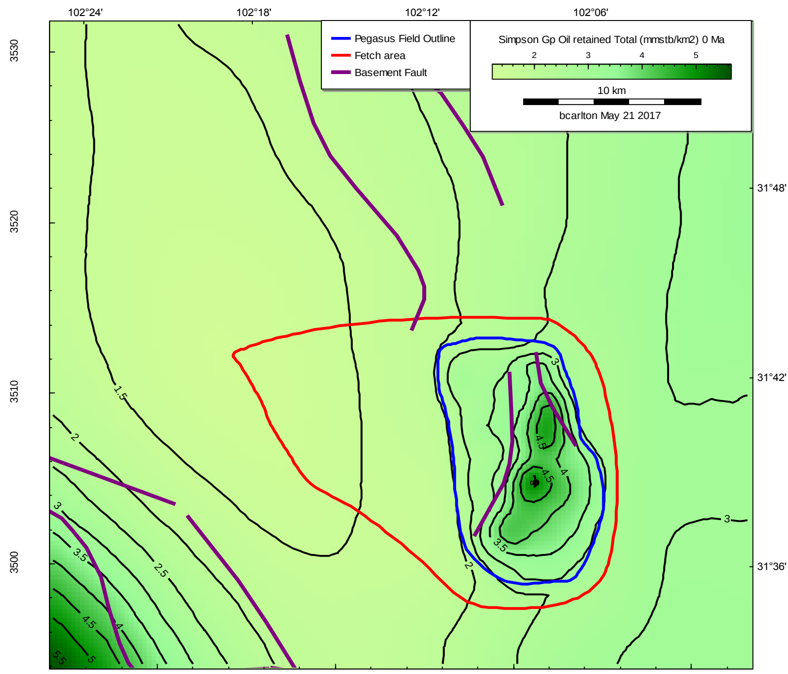

Figure A- 101. Simpson Group total oil retained at 0 Ma for Working Hypothesis 4.

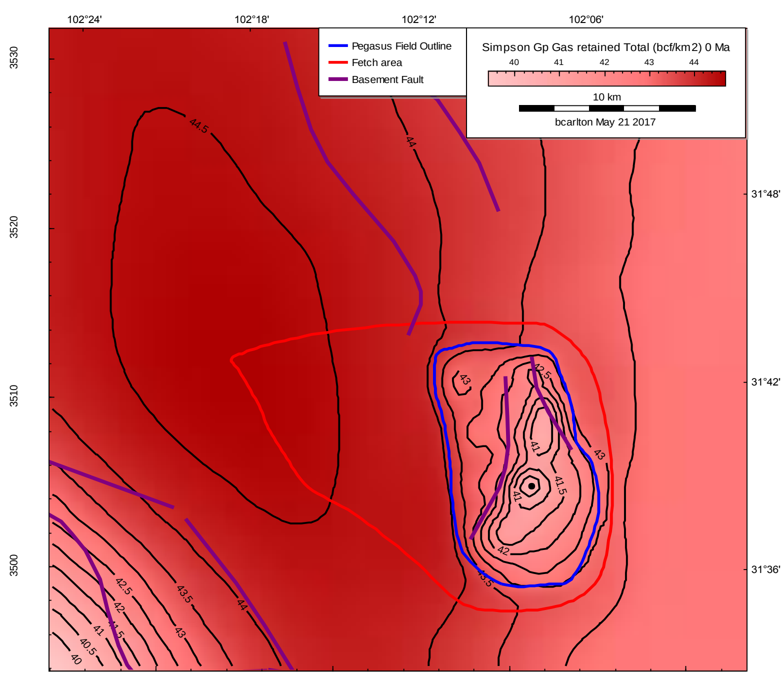

Figure A- 102. Simpson Group total gas retained at 0 Ma for Working Hypothesis 4.