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Correlation of Fluid Overpressure and Hydrocarbon Presence in the Tyler Formation, North Dakota

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INTRODUCTION

The Tyler Formation of North Dakota contains several organic-rich shale intervals that are regionally extensive and possibly oil-saturated (Nesheim and Nordeng, 2011). These shale intervals are rich in Total Organic Carbon (TOC) and often have high Hydrogen Index (HI) values indicating they are oil-prone, excellent quality source rocks that could develop into a successful resource play (Nesheim and Nordeng, 2011). The question, however, is where these organic-rich shales are thermally mature and have generated significant quantities of hydrocarbons.

Fluid pressure analysis can be an effective method for determining where source rocks are thermally mature and saturated with hydrocarbons. For example, Meissner (1978) examined fluid pressures within the Bakken Formation and found that in the shallower areas of the Williston Basin, where the Bakken does not produce significant oil and gas, the fluid pressure gradient is ≈ 0.46 psi/ft. In the deeper parts of the Williston Basin, where the Bakken Formation produces economically extractable oil and gas, Meissner (1978) found that fluid pressure gradients increase to upwards of 0.76 psi/ft., which he attributed to intense oil generation by the organic-rich upper and lower Bakken shales.

There are two primary types of pressure acting upon sedimentary rocks, lithostatic pressure and fluid pressure. Lithostatic pressure is the gravitational force exerted upon the solid component of a buried rock caused by the weight of the overlying burden. Lithostatic pressure typically has a pressure to depth gradient of around 1.0 psi/ft. Fluid pressure, which is the focus of this study, can be slightly more complex.

Most sedimentary rock intervals within the Williston Basin have a hydrostatic (normal) fluid pressure gradient, which is 0.43 psi/ft. for fresh water and 0.46 psi/ft. for salt water. A hydrostatic pressure gradient is caused by the weight of the overlying water column and indicates that a formations fluid system is in "open" hydraulic communication with the surrounding strata all the way up to the surface. An abnormal fluid pressure gradient (≠ 0.43-0.46 psi/ft.) indicates a formation has a "closed" fluid system. A "closed" fluid system occurs when low to impermeable layers seal a formations fluid system off from hydraulic communication with the surrounding strata. There are several processes that may cause abnormal fluid pressures within a "closed" system. One such process is intense oil generation (Fig. 1).

There are two schools of thought regarding hydrocarbon generation and fluid overpressure, the static school and the dynamic school (Bredehoeft et al., 1994). The static school believes that fluid overpressure can be caused by hydrocarbon generation and maintained indefinitely by impermeable seals (Hunt, 1990; 1991). The dynamic school, however, does not believe in impermeable rocks, noting that all rocks are permeable to one degree or another (Tóth et al., 1991; Bredehoeft et al., 1994). Therefore, according to the dynamic school, fluid overpressure is only maintained for extended periods of geological time if hydrocarbon generation is continuous (Tóth et al., 1991). In either case, there appears to be a consensus that fluid overpressure can be the result of hydrocarbon (oil) generation.

The Tyler Formation has previously been documented to contain areas of fluid overpressure as well as areas of hydrostatic pressure (Nordeng and Nesheim, 2010). The purpose of this study is to map the extent of fluid overpressure and examine if fluid overpressure correlates with hydrocarbon presence in an effort to aid oil and gas exploration of the Tyler Formation in western North Dakota.

METHODS

Tyler Formation fluid pressures were examined to differentiate areas with normal, hydrostatic fluid pressure gradients (~0.46 psi/ft.) from areas with abnormally high fluid pressure gradients (>0.46 psi/ft.). This study examined pressure data from 29 drill stem test's run on the Tyler Formation in western North Dakota (Table 1). A drill stem test (DST) is a procedure used to determine the productive capacity, pressure, permeability, and/or extent of a hydrocarbon reservoir (Oilfield Glossary-Schlumberger.com). The DST's examined in this study are either from wildcat wells, wells in established fields that did not substantially produce from or inject into the Tyler, or wells within producing Tyler fields that were drilled and tested prior to or shortly after field production began. DST's that may have been compromised by fluid production and/or injection were not examined in this study. Approximate Tyler Formation fluid pressures were calculated using the Horner plot method (Horner, 1951), which extrapolates a formation's fluid pressure using DST time-pressure data (e.g. Fig. 2). Fluid pressure gradients (psi/ft.) were calculated by dividing the extraolated fluid pressure (psi) by the depth to the top of the DST interval (ft.).

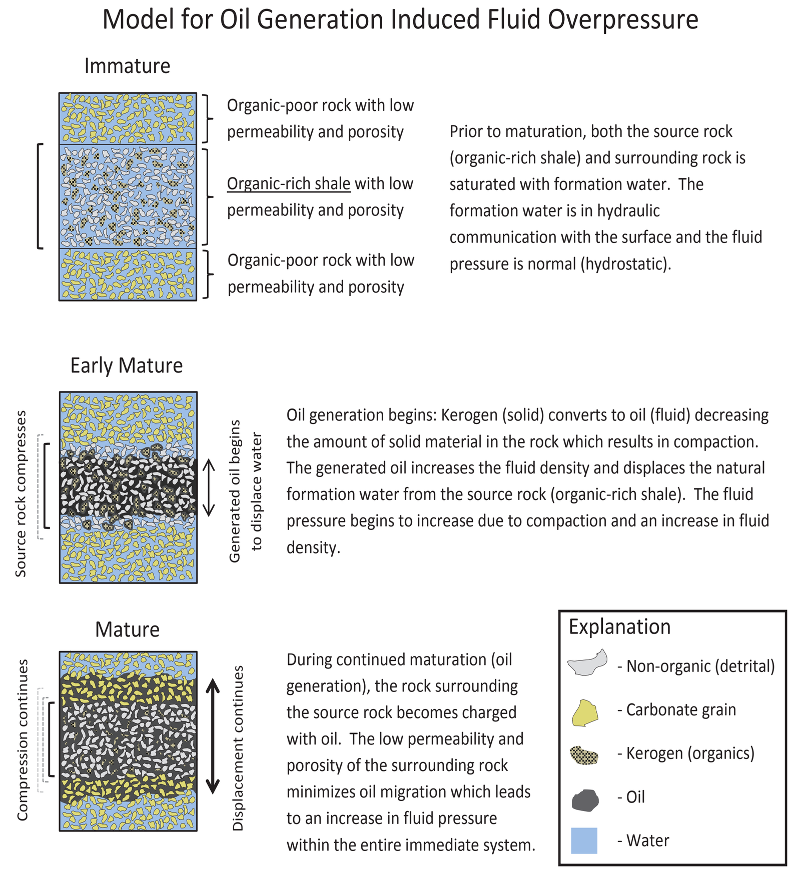

Figure 1. Schematic diagram depicting fluid displacement during hydrocarbon generation, modified after Meissner (1978).

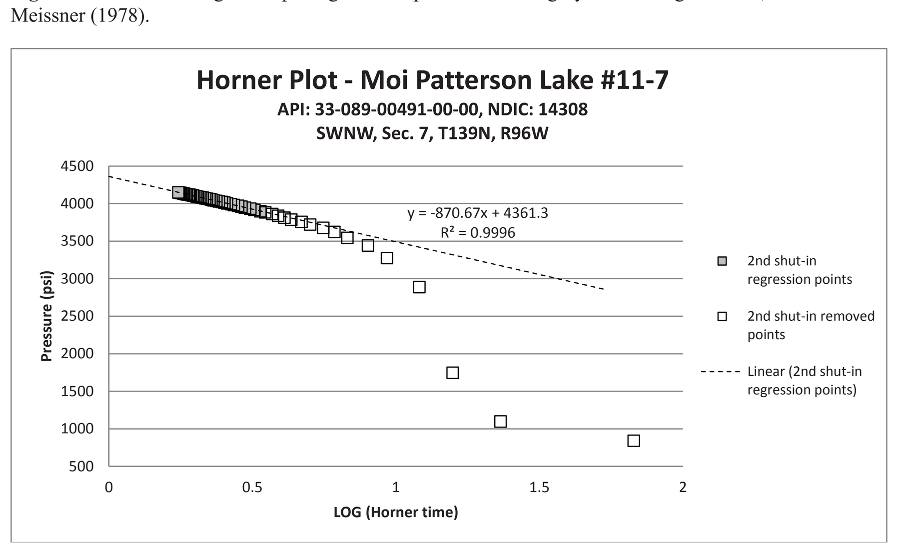

Figure 2. Example of a Horner plot showing time-pressure data measured during the 2nd shut-in period of an open hole drill stem test (DST) on the Tyler Formation (7,762-7,785 ft. M.D.) from Burlington Resources Moi Patterson Lake #11-7. The extrapolated fluid pressure (Horner, 1951) from the DST is ~4,361 psi at a depth of 7,762 ft., which yields a pressure gradient (0.56 psi/ft.), which is above the expected hydrostatic pressure range (0.43-0.46 psi/ft.). The fluid pressure extrapolated from the 1st shut-in period was 4,259 psi (0.548 psi/ft.). The fluid recovered in this test was 1,020' of gas cut mud and 627' of highly oil and gas cut mud. Cumulative production as of July, 2011 out of the Tyler pool for this well is 130,176 barrels of oil, 2,721 MCF of gas, and 1,079 barrels of water (this well is still producing from the Tyler Formation).

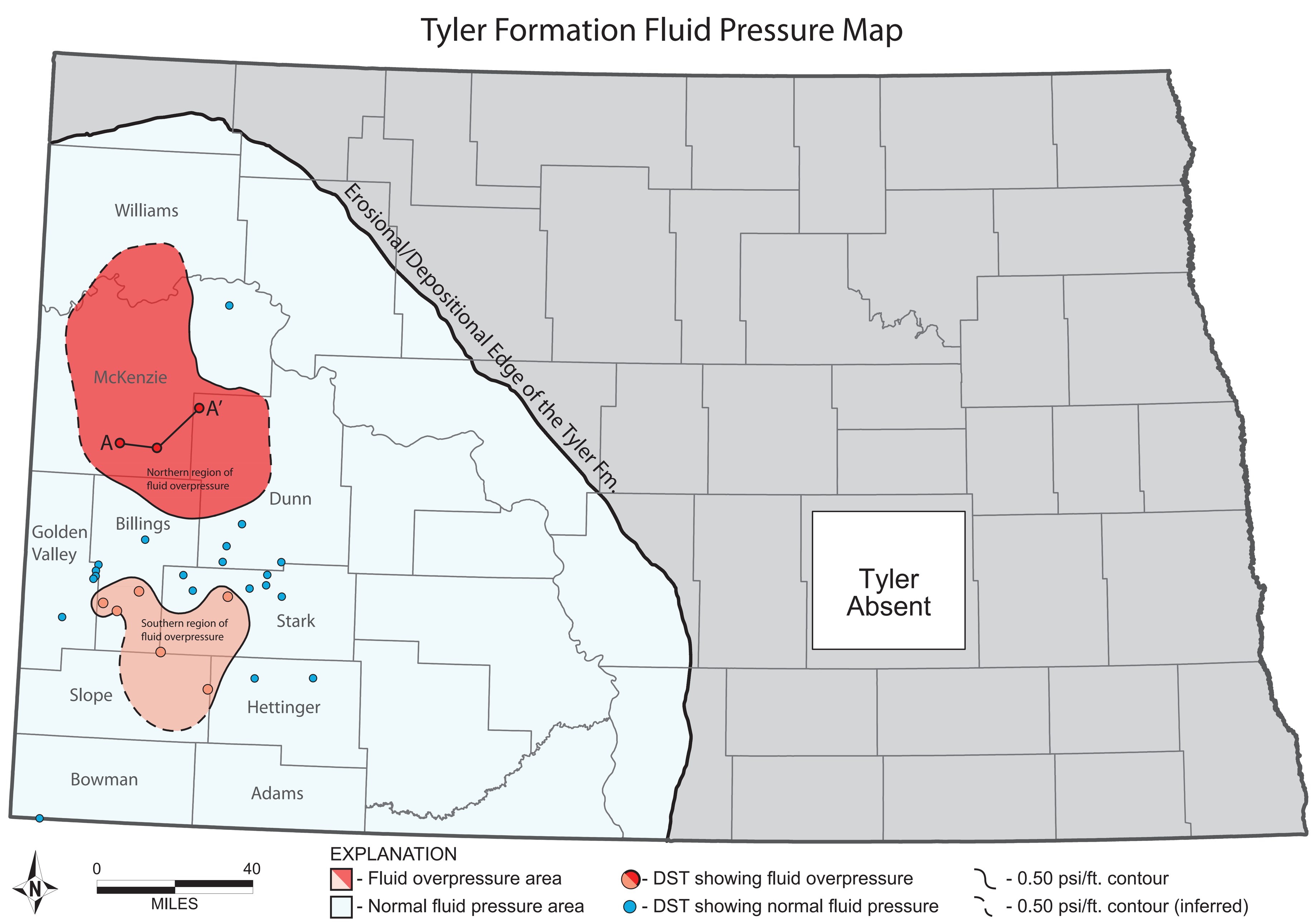

Figure 3. Map showing the approximate areas where the Tyler Formation has abnormally high fluid pressure. The locations of the 29 DST's (wells) used to generated the map are shown by the red and blue circles. A-A' shows the orientation of the Figure 10 cross-section.

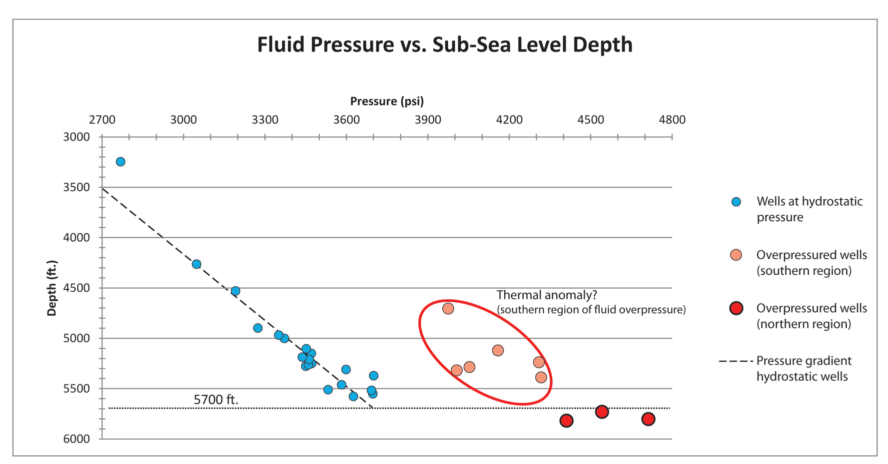

Figure 4. Diagram of extrapolated Tyler Formation fluid pressures plotted against the Tyler Formation top sub-sea level depth.

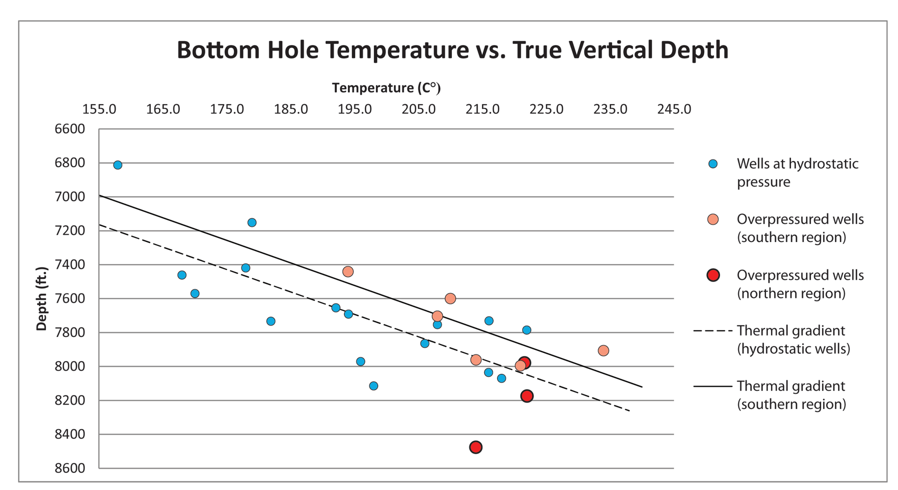

Figure 5. Diagram of bottom hole temperatures (measured during the DST) of the Tyler Formation versus depth. The six wells from the southern area of overpressure (red circles) have a higher thermal gradient (°C/ft.) than the other wells (blue and green circles).

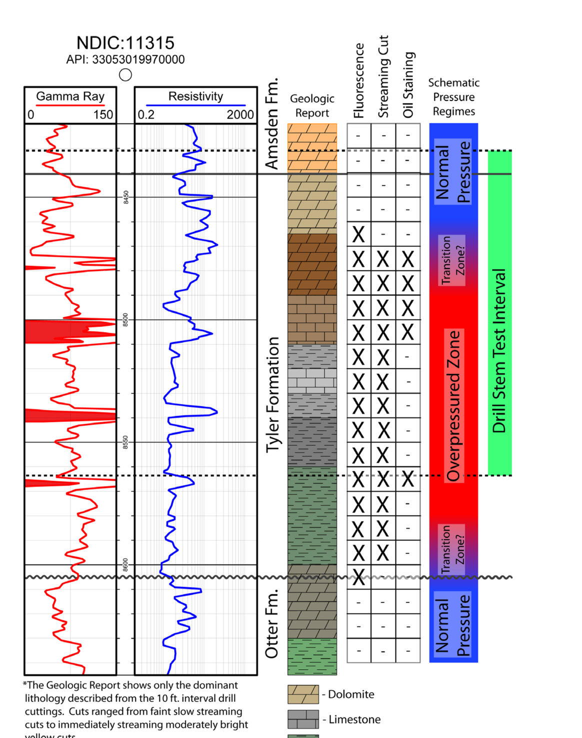

Figure 9. Compilation of several vertical logs of the Tyler Formation from well #11315, including (moving left to right): gamma ray and resistivity logs, a lithological log along with a record of several types of oil shows borrowed from the well file geologic report, a vertical schematic fluid pressure profile, and the DST Interval. The zone of fluid overpressure was modeled to extend along the vertical extent of oil shows within the drill cuttings, and normal fluid pressure wherever there were no shows. The transition from overpressure to normal pressure is speculated to be gradational, with a transitional pressure zone between the normal and overpressure zones, but it may be non-gradational and abrupt.

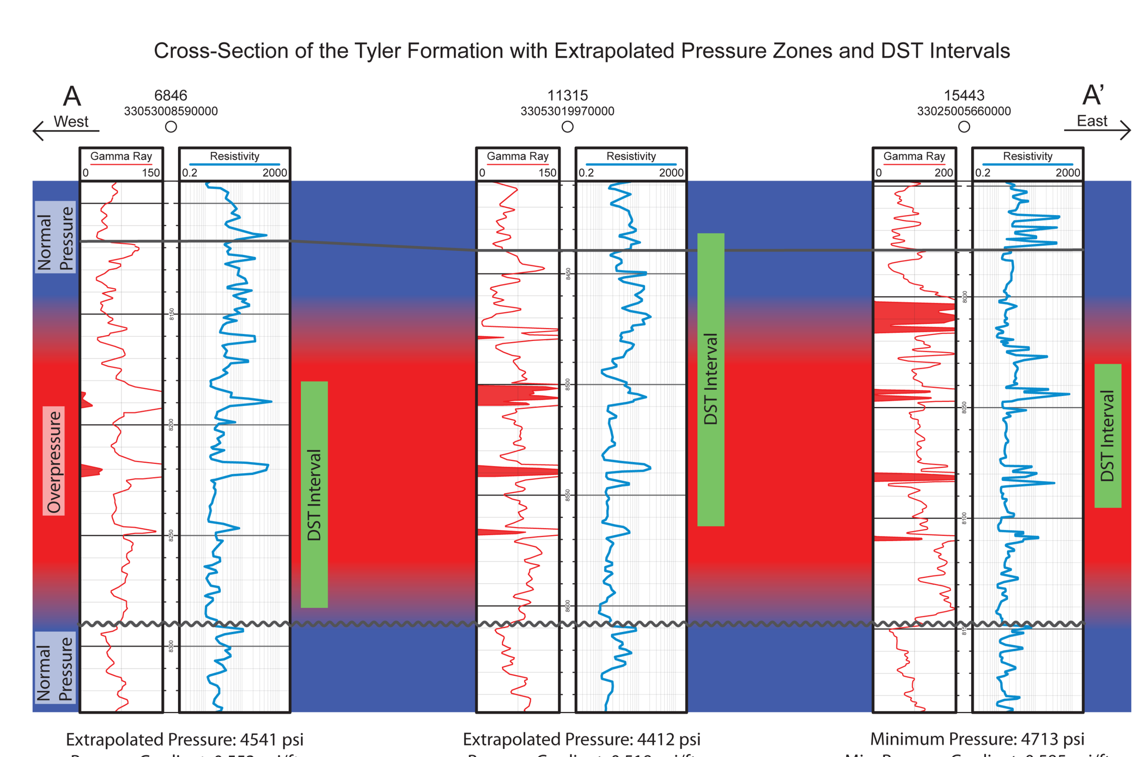

Figure 10. East to west cross-section of the Tyler Formation showing approximate zones of fluid overpressure versus normal pressure and the DST interval from each well. The fluid pressure and pressure gradient calculated from the DST's is listed below each well. Note that the highest fluid pressure and pressure gradient is from the DST with the smallest interval located in the central portion of the Tyler Formation (#15443). The three lower most gamma ray spikes within the Tyler Formation are believed to be organic-rich marine shale, which are excellent quality source rocks for oil generation (Nesheim and Nordeng, 2011).

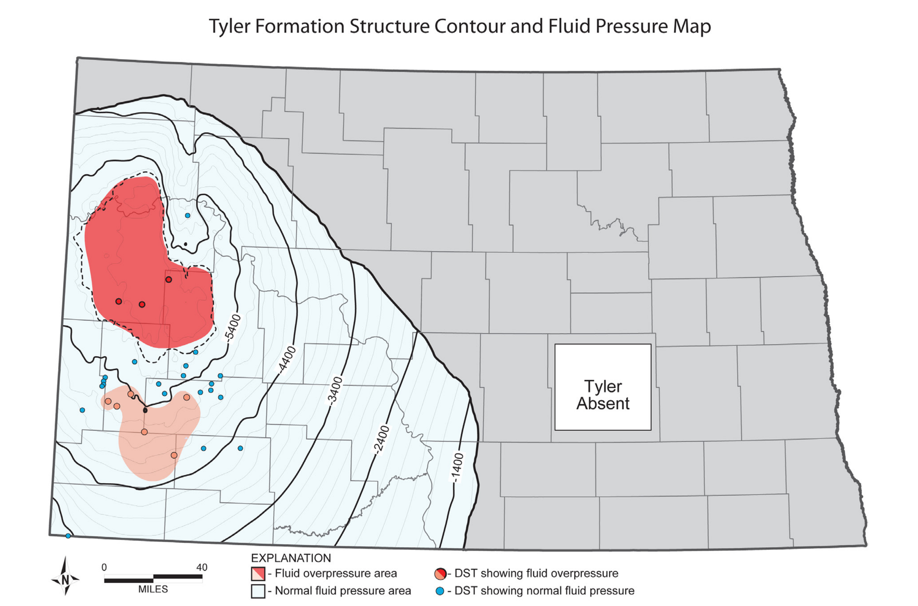

Figure 6. Structure contour map of the Tyler Formation surface with the approximate areas of fluid overpressure. The northern area of overpressure is defined approximately by the 5,650 ft. (dashed line) contour while the southern area of overpressure is approximated by well control and not depth.

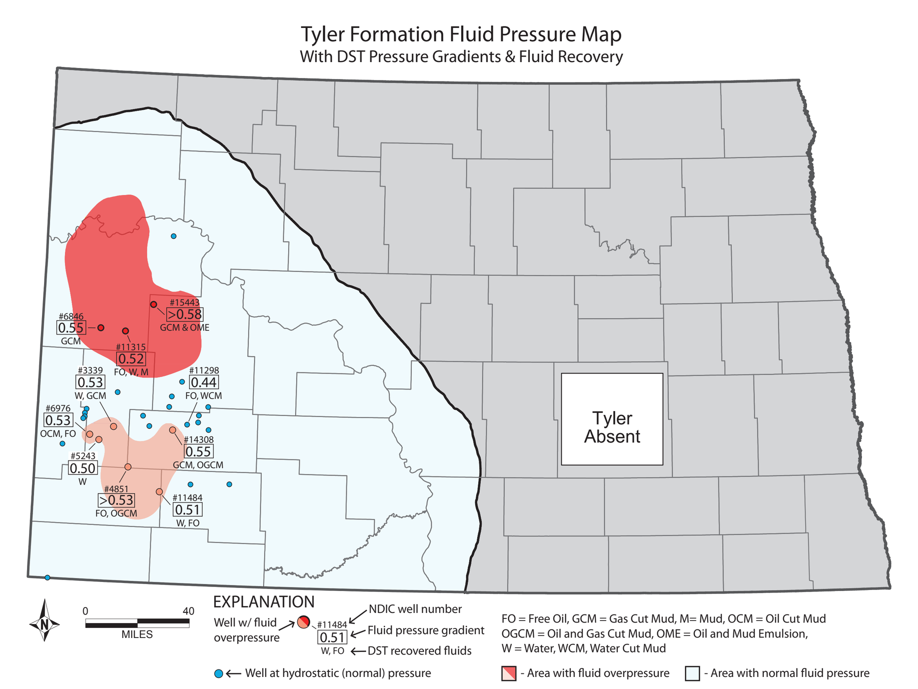

Figure 7. Fluid pressure map of the Tyler Formation with DST pressure gradients and fluid recovery for the nine wells with fluid overpressure.

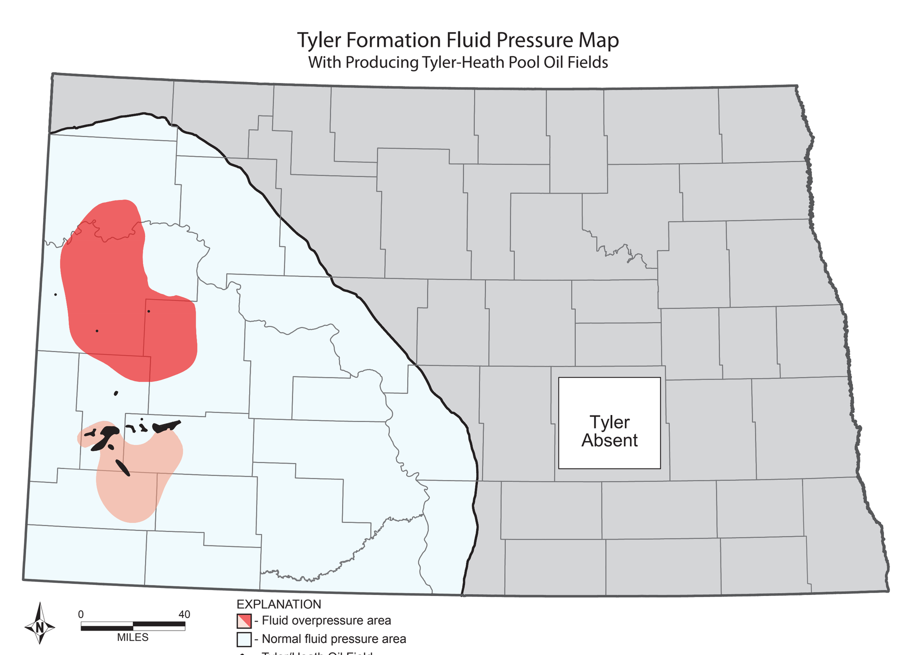

Figure 8. Fluid pressure map with areas of oil and gas production from the Tyler Formation. The Dickinson-Fryburg trend refers to the east-west distribution of productive Tyler oil fields in southwestern North Dakota.

Table 1. Well and DST information compiled by this study.

NDIC Well #	API	BHT (°F)	Test Interval		Interval Length (ft)	Fluid Pressure (psi)	Pressure Gradient (psi/ft)	Tyler Fm. Top	Tyler Fm. Top	DST Fluid Recovery		
			Top	Bottom				TVD	SSLD	Water	Mud	Oil
919	33053000690000		7430	7483	53	*3275	*0.439	7271	4901	1470		
1926	33041000020000	158	6835	6866	31	3048	0.445	6814	4265	5580		
3339	33007000560000	221	8026	8057	31	4317	0.537	7996	5390	500	60	
4575	33089000670000	216	8079	8125	46	3582	0.442	8036	5461	6350	**470	
4851	33089000950000	234	7974	7996	22	*4158	*0.523	7906	5123		**31	7904
4920	33089001050000		8215	8300	85	3626	0.437	8206	5579	3704		
5104	33033000350000	216	7766	7820	54	3451	0.443	7730	5278	5828		
5157	33025000440000		7838	7926	88	*3698	*0.469	7762	5551	6951	226	
5167	33033000360000	208	7833	7868	35	3599	0.458	7754	5311		225	
5243	33007001520000	214	7985	8136	151	4007	0.497	7963	5322	3090		
5274	33025000480000	168	7504	7553	49	3462	0.460	7464	5209	2632	172	
5282	33089001350000	192	7743	7750	7	3471	0.448	7651	5149	6292		
5399	33025000520000	196	8101	8231	130	3701	0.456	7977	5372	7180		
5477	33089001640000	170	7637	7674	37	3452	0.453	7572	5105	6664	186	
5567	33011001940000		6180	6246	106	2769	0.447	6252	3247	354	91	
5722	33033000400000	222	7844	7871	27	3371	0.429	7783	5003	6901		
5754	33089001960000	178	7447	7586	139	3351	0.449	7421	4971	1741		
6846	33053008590000	222	8180	8282	102	4541	0.552	8174	5731		**568	
6976	33007003460000	210	7607	7669	62	*4054	*0.531	7600	5286		**578	60
7432	33007004720000	218	8100	8134	34	3533	0.436	8069	5511	470	277	
9815	33025003540000	198	8166	8205	39	3693	0.451	8117	5518	14857	653	
10522	33041000320000	179	7135	7364	229	3191	0.448	7152	4532	4000	2052	
11298	33089003490000	182	7804	7825	21	3438	0.440	7734	5187		144	302
11315	33053019970000	214	8431	8563	132	4412	0.519	8475	5819	269	133	2586
11484	33087001200000	194	7540	7556	16	3975	0.527	7440	4707	79		5
11510	33033001650000	194	7746	7772	26	3470	0.447	7693	5250	72	89	
11525	33033001660000	206	7892	7939	47	3460	0.440	7861	5260	4530	643	
14308	33089004910000	208	7762	7785	23	4310	0.554	7705	5242		**1647	
15443	33025005660000	222	8030	8095	65	*4713	*0.585	7978	5806		**410	56

*Minimum Fluid Pressure/Pressure Gradient
Converted barrels to feet assuming 1 BBLS = 164 ft.
**Oil and/or gas cut mud

RESULTS

Nine of the DST's examined showed the Tyler Formation to have abnormally high fluid pressures (> 0.46 psi/ft.) while the other twenty showed Tyler Formation fluids to be at hydrostatic pressure (~0.43-0.46 psi/ft., Table 1). Of the nine DST's that exhibit overpressure, six of them cluster together in southwestern North Dakota and the other three define a northern area of overpressure in west-central North Dakota (Fig. 3). The extrapolated fluid pressures were compared to depth (Fig. 4), bottom hole pressure (Fig. 5), spatial location (Fig. 6 and 7), and oil production (Fig. 8) to better understand both the cause and regional extent of fluid overpressure within the Tyler Formation fluid system.

The extent of the northern area of fluid overpressure is poorly defined by DST/well control (Fig. 3). However, all three DST's with a Tyler Formation top greater than 5700 ft. below sea level have a pressure gradient above 0.46 psi/ft. (Table 1; Fig. 4 and 6), while all off the DST's at hydrostatic pressure have a Tyler Formation top less than 5600 ft. This depth versus fluid overpressure relation indicates that fluid overpressure in the northern area is a function of sub-sea level depth. Basically, at depths of 5600-5700 ft. below sea level, subsurface temperatures are high enough to thermally mature Tyler source rock and generate oil. Therefore, the extent of the northern area of overpressure is estimated by tracing the ~5650 ft. sub-sea level depth contour of the Tyler Formation top (Fig. 6).

The southern area of fluid overpressure does not appear to be strictly a function of depth. All six DST's that define the southern area of fluid overpressure have a similar Tyler Formation top depth range as the adjacent DST's at hydrostatic pressure (Fig. 4 and 6). The average temperature gradient of the Tyler Formation for these six DST's at overpressure, however, is higher than the average temperature gradient of all the other wells (Fig. 5). This temperature data indicates that the thermal gradient of the Tyler Formation in the southern fluid overpressure area may be higher than the surrounding areas. The higher thermal gradient may have thermally matured the Tyler Formation in only part of southwestern North Dakota (Fig. 3 and 6).

DISCUSSION AND INTERPRETATION

There are several processes that can cause fluid overpressure, one of which is the generation of hydrocarbons. To test whether hydrocarbon generation is the process that developed fluid overpressure in the Tyler Formation, the DST fluid recovery records were compiled and examined. If fluid overpressure is caused by intense oil and/or gas generation, than the DST fluids recovered from wells with overpressure should contain more oil and/or gas than wells at hydrostatic pressure. Out of the nine DST's that showed Tyler Formation fluids to be at overpressure, eight recovered some type of hydrocarbon show such as free oil, gas cut mud, oil cut mud, and/or oil and gas cut mud with minimal water (Table 1, Fig. 7). The one DST at overpressure that did not have record of oil or gas recovery was from well #5243 (Table 1, Fig. 7), which only showed minimal overpressure with a pressure gradient of 0.497 psi/ft. Of the twenty DST's that showed Tyler Formation fluids to be at hydrostatic pressure, only one reported free oil recovery and another very slightly water and gas cut mud (Table 1, Fig. 7). So with only two or three exceptions, DST's with Tyler fluids at overpressure contain oil and/or gas while DST's with Tyler fluids at normal (hydrostatic pressure) do not.

Oil and gas production also correlates with the areas of fluid overpressure. Figure 8 displays the areas of Tyler Formation oil and gas production along with the areas of fluid overpressure. The Dickinson-Fryburg trend, where oil and gas is produced from bar-type and channel sand deposits, partially overlaps with the southern area of overpressure (Fig. 8). Two wells have produced oil out of the northern area of overpressure, with a third small producer just to the west (Fig. 8). The overlap with areas of oil and gas production further verifies the existence of regional fluid overpressure within the Tyler Formation and that the overpressure is consistent with the generation of hydrocarbons.

There are three components necessary to produce oil generation induced fluid overpressure within the Tyler Formation: 1) sufficient quantities of kerogen to source oil and/or gas, 2) thermal maturation of kerogen to generate oil and/or gas, and 3) hydraulic seals both above and below the organic-rich interval to minimize hydrocarbon migration. Without thermally matured kerogen, there would be no source for the additional fluid and/or gas necessary to cause overpressure. Also, without sufficient seals, substantial amounts of generated hydrocarbons would be able to migrate from the system and the fluid pressure would return to the hydrostatic gradient. Therefore, fluid overpressures observed by this study suggest that the Tyler Formation contains mature, high quality source rocks that are bounded above and below by low to impermeable rocks that extend across part of western North Dakota.

While abnormally high fluid pressures correlate with hydrocarbon charged, thermally mature areas, not all of the extrapolated fluid pressures and pressure gradients are equally comparable with one another for two reasons. First of all, the examined DST intervals varied greatly in length from 7 ft. to 229 ft. (Table 1). Secondly, some of these DST's tested the middle and/or upper parts of the Tyler Formation (e.g. #11315 in Fig. 9 and 10) while others tested middle and/or lower parts (e.g. #6846 and #15443 in Fig. 10). Since DST's vary in interval length and vertical location within the Tyler section, any attempt at contouring the Tyler Formation pressure gradient would be very difficult because the Tyler Formation may be compartmentalized in terms of fluid pressure.

Areas, or zones, of fluid overpressure are not only defined by lateral, horizontal boundaries, but also by vertical boundaries. Figure 9 displays a series of logs from well #11315 along with vertically interpreted pressure domains. The DST interval from well #11315 extended across both zones of fluid overpressure and normal pressure (Fig. 9). The fluid pressures recorded during the DST were likely pressure values intermediate between the normal and overpressure zones.

The variance in fluid pressure gradients begins to make sense once you examine the fluid overpressure zone and the DST intervals from wells in the northern overpressure area. Figure 10 is a cross-section of the three wells from the northern overpressure region that shows gamma ray and resistivity logs of the Tyler Formation, the DST interval, and the zones of normal and overpressure extended from well #11315. All three DST's extend across the central portion of the Tyler Formation and show fluid overpressure (Fig. 10). However, the DST from #11315 extends above the proposed zone of overpressure by 30-50 ft. while the DST from well #6846 may extend 10-30 ft. below the overpressure zone. The DST's from wells #6846 and #11315 may have produced intermediate fluid pressure readings, between the overpressure and normal pressure zones. Each of these two wells has a pressure gradient significantly below that of well #15443, which had its DST run entirely in the proposed zone of overpressure (Fig. 10). Therefore, the fluid pressure gradient of these three wells may vary in part because of differences in location and interval length between the DST's.

CONCLUSIONS

1) The Tyler Formation of western North Dakota contains two areas of fluid overpressure. Fluid overpressure in the Tyler Formation is likely caused by intense hydrocarbon generation from thermally mature, excellent quality source rock bounded above and below by low permeability/porosity layers (seals).

2) In the deeper parts of the Williston Basin, west-central North Dakota, the Tyler Formation has been buried deep enough to encounter temperatures capable of thermally maturing organic-rich shale and generating oil and gas.

3) Part of southwestern North Dakota has an elevated subsurface temperature gradient that leads to higher temperatures at shallower depths thus causing oil generation and a second area of fluid overpressure in the Tyler Formation.

4) While the pressure data compiled by this study can be used to identify areas of fluid overpressure within the Tyler Formation, the data is not sufficient to generate pressure gradient contours due to variations in the DST interval length and stratigraphic location.

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