EVALUATING THE ECONOMIC IMPACTS OF GROUNDWATER PUMPING FOR HYDRAULIC FRACTURING ON AQUIFER STAKEHOLDERS IN THE EAGLE FORD SHALE, TEXAS

A Thesis

by

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ABSTRACT

The Eagle Ford (EF) Shale Play has been under intensive development for oil and natural gas production since 2011. This region is a major energy supplier to the United States and worldwide, currently producing over 1.2 million barrels of oil and over 7 billion cubic feet of natural gas per day. However, with the average volume of a single hydraulic fracture job increasing from 17,000 m^3 of water in 2011 to over 37,000 m^3 per treatment in 2017, this new water demand in a water scarce region is a growing concern for south-central Texas. Although the water used in hydraulic fracturing (HF) Texas accounts for less than 1% of total, statewide water consumption, water supplies are distributed unevenly so that many regions of Texas were under water stress prior to the start of fracking.

Owing to energy development, the region has experienced extensive declines in water levels in wells of up to 60 meters in areas of the western play since hydraulic fracturing initially commenced in 2009 (Scanlon, 2014). This addition of a new, competing groundwater-using sector has residents concerned about their water security. Their wells, which supply local households, agriculture, municipalities and other industries, tap the same aquifers as the fracking water supply wells. Although water is increasingly transferred long distances in Texas, this transportation is energy consumptive, expensive and

politically unpopular. This leads to a competitive advantage, economically and politically, in using local groundwater.

Groundwater pumping for hydraulic fracturing tends to occur in spatially concentrated areas over short, but intense time periods. Therefore, conflicts may still arise when drawdown in the water level in wells of neighboring groundwater users are caused by the new pumping activity. Understanding how this short-term, localized pumping for fracking causes the propagation of hydraulic head drawdown throughout the aquifer, thereby impacting other users, is integral in determining the economic impacts of water production to all sectors, such as agriculture, manufacturing, and livestock, to name some. These costs may range from increased pumping costs, replacing damaged pumps, well deepening, or securing and transferring water from new sources. Combining the FracFocus Database, a registry required by the state for producers to report frac chemicals and volumes used at all well sites, with spatial analysis and groundwater modelling, to estimate the effects of transient drawdown can aid in the planning and use of groundwater resources in the region so that all sectors of society and industry can continue production with minimal competition.

This study undertakes a straightforward approach to estimate this localized, ephemeral drawdown in the principal aquifers utilized for fracking in the EF using publicly available data. Although groundwater is critical to several sectors of the economy in Texas, there is a gap in knowledge regarding how an aquifer responds to pumping for fracking across a large region- on a local scale.

This is because, unlike other sectors which pump at relatively steady rates, the pumping at any given location to supply water for nearby fracking is short-lived.

By utilizing basic hydrogeologic principles in a transparent method, this study provides a module that predicts the impacts from this short-lived pumping and estimates the pumping cost impacts imposed on other sectors. This study identified key stakeholders impacted by transient drawdown from HF pumping and estimated their additional pumping costs in response to these times. Although drawdown was found to disproportionately impact well owners over the region, it was not always the determining factor in maximum cost impacts. Of the six Groundwater Conservation Districts (GCDs), or Underground Water Conservation District (UWCD), included in this study, wells in Wintergarden and McMullen GCD experienced the greatest drawdown impacts from groundwater pumping to supply HF operations, at approximately 200 and 300 m in the most extreme cases, respectively. However, the greatest additional pumping cost over the study period in these cases were found to impact a small number of well owners residing in McMullen GCD and Gonzales UWCD, totaling approximately $200 each.

The framework and results from this module could be added to a trans-disciplinary model developed by the Water-Energy-Food (WEF) nexus of professionals who are working to enhance efficiency within all domains. While water need/demand is a rigorously studied subject in the realm of WEF research, the surbsurface geologic and hydraulic constraints are commonly unaccounted for. With this modeling approach we hope to bridge this subsurface knowledge gap and give professionals from all backgrounds a method for assessing groundwater competition between all sectors.

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CONTRIBUTORS AND FUNDING SOURCES

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This work was supervised by a thesis committee consisting of Dr. Peter Knappett of the Department of Geology & Geophysics, Dr. Rabi Mohtar of the Department of Biological & Agricultural Engineering, and Dr. Gretchen Miller of the Department of Civil Engineering.

All work for the thesis was completed by the student, in collaboration with Dr. Peter Knappett of the Department of Geology & Geophysics.

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WEF NEXUS INITIATIVE

NOMENCLATURE

AFY	Acre-Feet/year
API	American Petroleum Institute (well identifier)
DOE	Department of Energy
EF	Eagle Ford
EUR	Estimated ultimate recovery
GCD	Groundwater conservation District
GIS	Geographic information system
HF	Hydraulic fracturing
IP	Initial production (oil & gas)
IQR	Inter-quartile range
MBO	Million barrels of oil
NLCD	National Land Cover Database
SDR	Submitted Drillers Reports
S	Storativity
T	Transmissivity (m^2/day)
TDS	Total dissolved solids
TIN	Triangulated irregular network
UWCD	Underground water conservation district
VOC	Volatile organic compounds
WEF	Water-Energy-Food Nexus

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1. INTRODUCTION

The abundant and widely distributed aquifers of Texas have permitted the state's economic development throughout the 20th century and into the 21st. The major groundwater-using sectors are agriculture, municipal supply, and oil and gas production. The recent development of modern hydraulic fracturing technology in the Barnett Shale in north Texas in the 1990's introduced new demand for fresh groundwater, not only in Texas, but in water-scarce regions around the world (Scanlon, 2014). Texas has three major shale plays that are actively being hydraulically fractured for natural gas and oil: the Barnett Shale in north Texas, the Eagle Ford Shale in central Texas, and the Permian Basin straddling the borders of Texas and New Mexico. These shale plays all have their own unique set of water resources and issues connected to developing oil and gas through the use of hydraulic fracturing. Consequently, each unique setting contributes to a certain scope of impacts experienced by residents, businesses, and sectors of the economy. This study will attempt to quantify these impacts by analyzing the impact of groundwater pumping for fracking on: 1) water levels in wells supplying other sectors; and 2) the resulting economic impacts of this drawdown on the other sectors.

Since the first well drilled in 2008, fracking the Eagle Ford shale has consumed large volumes of water to recover valuable oil and natural gas.

Between 2009 and 2013, over 40 billion gallons of water were used for hydraulic fracturing in this play, making the Eagle Ford the largest consumer of water for tight shale energy production in the U.S. (Parham, 2017). This drastic increase of water use in this region poses some risk to existing stakeholders in the aquifer. These stakeholders are mainly in the agriculture and municipal water-use sectors, where other potentially impacted water-use sectors include livestock, industrial, and domestic sectors. The competition between these users may limit groundwater production owing to increased costs of water in this already water-stressed area. With projected water shortages increasing every decade in the Region L Water Planning Group of Texas, groundwater levels must be continually measured and modeled to quantify the impacts of this particularly water-intensive driver of economic growth that is dependent on present and future water levels in impacted aquifers. (TWDB, 2015).

This study focuses on the interrelations between water and energy production, specifically water used in hydraulic fracturing, to quantify net social and economic impacts from this water use at a regional and local scale. In addition to evaluating the impacts of water use on hydraulic heads in aquifers, to estimate trade-offs we explore the economic and social benefits of oil and gas extraction on the region this is performed. We hope this may enable a more transparent management of our hidden groundwater resources by private and public entities.

1.1 Objectives

1) Assess the impacts of short-term, intense pumping to supply fracking, on the availability of groundwater for surrounding cities, towns, farms, and rural households.
2) Estimate the economic impacts of localized water scarcity created by pumping for fracking on other groundwater-dependent sectors within the EF.
3) Develop a straightforward groundwater drawdown modeling technique that can be easily understood and utilized by professionals from various backgrounds to assess groundwater competition at the local scale caused by a groundwater-using sector that uses high quantities of water, over short time periods.

2. STUDY AREA & LITERATURE REVIEW

2.1 Eagle Ford Regional Overview

2.1.1 Geography

The Eagle Ford shale spans 23 counties in Texas. Twenty-one of these counties lie within the Region L South Central Texas Water Planning Group of the Texas Water Development Board (TWDB). These are Atascosa, Bexar, Caldwell, Calhoun, Comal, DeWitt, Dimmit, Frio, Goliad, Gonzales, Guadalupe, Hays (partial), Kendall, Karnes, La Salle, Medina, Refugio, Uvalde, Victoria, Wilson, and Zavala counties. There are 4 major cities in the region, with the most prominent city being San Antonio, located in the northern section of the region in Bexar county and home to a growing population of over 1.5 million (TWDB, 2015). The Eagle Ford shale is approximately 50 miles wide and 400 miles long, covering more than 20,000 square miles (13 million acres) of land extending south from the Mexican border up to East Texas (Gong, 2013).

2.1.2 Climate

The region in which the Eagle Ford shale is found lies within two major climate divisions: 1) Post Oak Savanna, characteristic of sub-tropical to sub-humid prairie, savanna, and woodlands in the East region; and 2) South Texas Plains, characteristic of semi-arid brushland in the West region (TWDB, 2012). Precipitation in these regions range from 50 cm/year in the west to 98 cm/year in the east (Figure 1) (Scanlon, 2014). Surface evaporative demand rates have the opposite spatial pattern as precipitation trends, with a net annual surface evaporation of 1.5 m/year in the west to 0.8 m/year in the east (TWDB, 2015). Sub-tropical regions are exceptionally hot and humid in the summers, averaging highs of 36°C, while winters are usually mild and dry, averaging lows of 7°C. Summer spans from May through September, during which occasional thunderstorms occur. Winter spans from November through March (TWDB, 2015). In this semi-arid region, evaporative demand exceeds precipitation, resulting in a landscape deficient of surface water resources. These regions are prone to frequent droughts, with 2011 marking the most intense one-year drought on record for the state of Texas (TWDB, 2012). Supplemented by a moderate to abnormally dry climate, the western portion of the play relies almost entirely on groundwater resources. In contrast, the eastern portion more commonly relies on surface water bodies to supply hydraulic fracturing (HF) (Freyman, 2014). Although surface water may be more readily available in the east, there are requirements for obtaining state permits for its use and permits may be suspended during times of drought (Water Use, 2018).

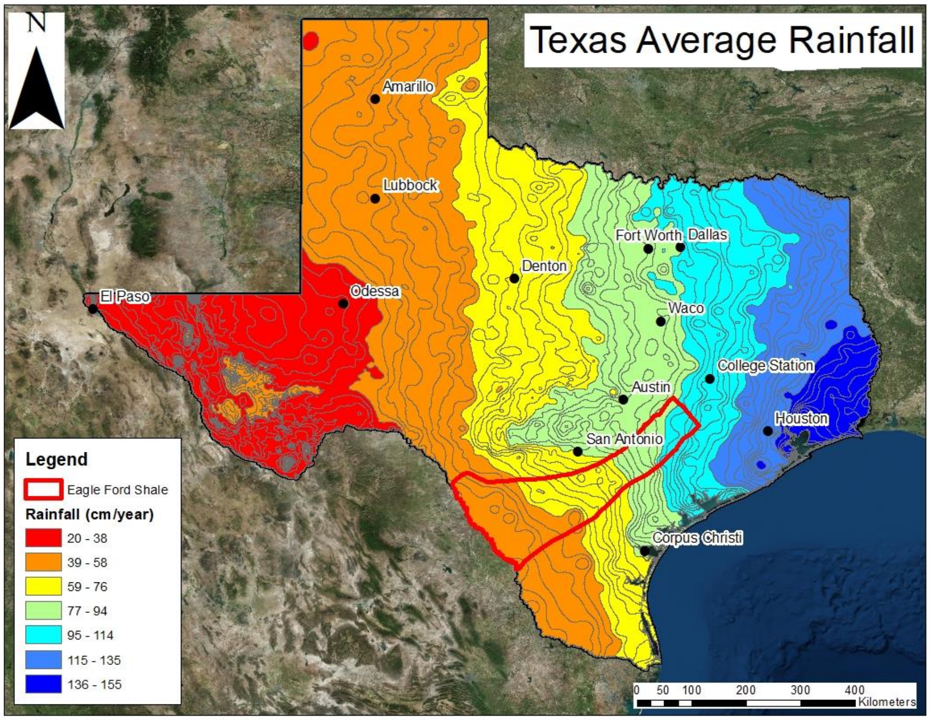


Figure 2-1: Average yearly rainfall across Texas, marking the Eagle Ford Shale area in red.

2.1.3 Regional Economy

The regional economy of South-Central Texas is based on agricultural and livestock production, mining, manufacturing, and trades and services. The trades and services sectors comprise approximately 48% of the regional economic activity, owing to a thriving tourist industry in San Antonio (TWDB, 2015). The manufacturing sector comprises approximately 27% of regional economic activity, creating fabricated metal products, industrial machinery, petrochemicals, and processing food (TWDB, 2015). The mining sector, dominated mostly by oil and gas production in the Eagle Ford shale, accounts for 22% of the regional economic activity (TWDB, 2015). To put this in perspective, total oil and gas production within the state of Texas makes up 11% of the state's economic activity. Texas oil and gas production specifically from fracking shale formations is produced from the Barnett Shale, Haynesville Shale, Permian Basin, and EF (2016, Texas). Other mining activities in the region include sand and gravel, which is used mainly in the production of cement. Lastly, agriculture accounts for 3% of the regional economic activity, mainly producing beef cattle, corn, and grain sorghum (TWDB, 2015). Details regarding each sector's water use will be presented in the following sections.

2.1.4 Population and Major Water Demand Centers

There are four major water demand centers in South-Central Texas. These centers are the cities of San Antonio and San Marcos, the Wintergarden region (also a GCD) south of the Edwards Aquifer area, and the Coastal area (TWDB, 2015). The San Antonio and San Marcos urban centers are where 83% of the region's population resides. The other 17% of the region's population reside in the rural areas of the Edwards Aquifer region, Wintergarden agricultural region, and the Coastal area. Irrigation to produce agricultural products is the leading water user in the Edwards Aquifer region and Wintergarden region. In contrast, water demand in the Coastal area is driven by the industrial sector and to a lesser extent agriculture (TWDB, 2015).

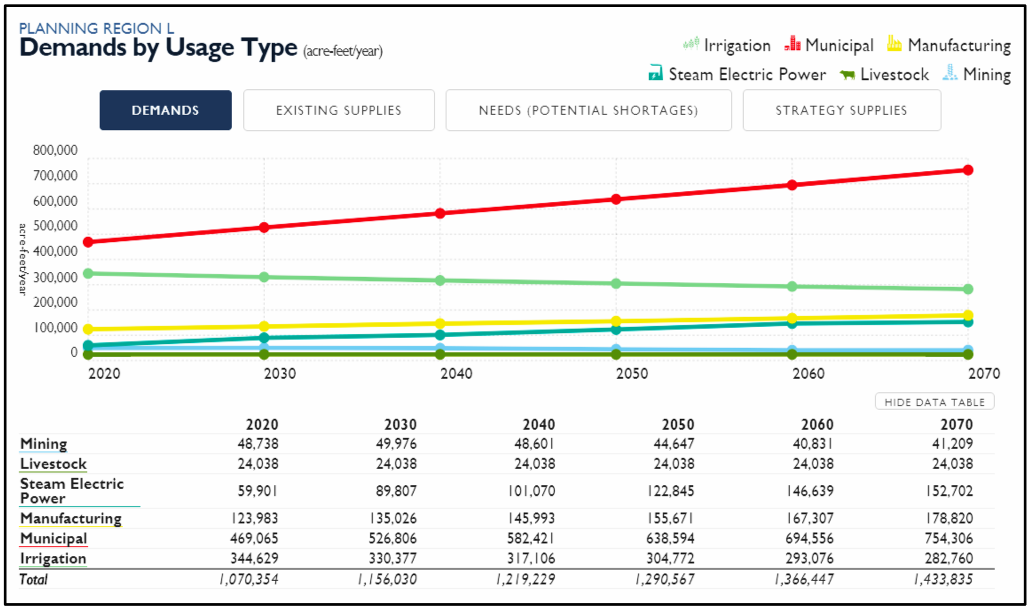
According to the Bureau of the Census, the population of South-Central Texas was 2,535,451 in 2010. This population was 2.5 times greater than the population in 1960 (TWDB, 2015). Region L's population is projected to steadily increase every decade. It is forecasted to surpass 4 million people after the year 2040. Focusing on the short-term, the total projected population of Region L is estimated to reach just over 3 million in 2020, with 2 million people residing in Bexar County (TWDB, 2015). Although the region's population is growing at a rate of 1.85 % a year, populations in counties such as DeWitt, Dimmit, Karnes, and Zavala are declining. There are less than 20,000 people in these counties which also have high oil and gas production from the EF.

2.2 Regional Water Use

2.2.1 Major Sectors and Projected Demands, Supplies, Needs

As part of state water planning, the Texas Water Development Board conducts regional and statewide assessments to quantify projected water demands, supplies, and needs. This is achieved through recording annual water use, surface water allocations, and estimating future population. When referring to projected demands in this section, water quantities are estimates based mainly on water use trends and projected population changes. Similarly, projected supplies account for current water supplies to a region, but added to the volume of any planned or in development water infrastructure currently underway. Projected supplies account for trends in surface water allocations, modeled available groundwater, and water transfer operations, to name some. Projected needs, or shortages, is essentially the difference between projected supplies and demands, meaning there are currently no approved water strategy plans to meet the projected needs of that year. A water strategy plan can range from conservation, developing new surface and groundwater supplies, conveyance facilities to move water resources to areas of need, and water reuse plans. Region L's municipal, irrigation, and manufacturing sectors demand the majority of total water use, with the remaining demands made by steam electric power generation, mining, and livestock production (Figure 2-2).

Total demands for the region are steadily increasing each decade while existing supplies remain constant, at about 1 million acre-feet per year (AFY). Demands currently exceed 1 million AFY and are projected to reach 1.5 million AF after the year 2070 (TWDB, 2017). Projected needs are expected to increase from 200,000 AFY in 2020 to 482,000 AFY by 2070 (TWDB, 2017). Planned water strategies are expected to satisfy projected shortages for every future planning decade up to 2070, except 2020, in which there will be a deficit of 21,000 AF (TWDB, 2017). Out of the total projected water demand for 2020, approximately 1 million AF, 4.5% of that demand is from the mining industry (TWDB, 2017). Water demand for the mining sector in Region L is expected to peak at 50,000 AFY during 2020 to 2030 and steadily decrease to 40,000 AFY by 2060.



	2020	2030	2040	2050	2060	2070
Mining	48,738	49,976	48,601	44,647	40,831	41,209
Livestock	24,038	24,038	24,038	24,038	24,038	24,038
Steam Electric Power	59,901	89,807	101,070	122,845	146,639	152,702
Manufacturing	123,983	135,026	145,993	155,671	167,307	178,820
Municipal	469,065	526,806	582,421	638,594	694,556	754,306
Irrigation	344,629	330,377	317,106	304,772	293,076	282,760
Total	*1,070,354*	*1,156,030*	*1,219,229*	*1,290,567*	*1,366,447*	*1,433,835*

Fig 2-2: Region L projected water demands by sector type. Reprinted from the Texas Water Development Board- Interactive State Water Plan (available at: texasstatewaterplan.org/region/L).

Looking closely at the water demands in Karnes County, one of the top oil producing counties in the state, TWDB reports a population under 16,000 and the top two main water users are municipal and mining. Municipal demand in Karnes County is just under 4,000 thousand AFY and mining demands 2,500 AFY. Municipal and mining water demand for the year 2020 is projected to comprise approximately 45% and 31% of the total water demand for Karnes County, respectively (TWDB, 2017). Although small compared to Regional L mining demands, these percentages of water demand illustrate how great the proportion of mining demand can vary across the region. Even though total water use is small in a county, compared to a metropolitan area, there can be large differences in the relative ranking of sectors based on their water demand between districts.

Located west of Karnes County nearing the Texas-Mexico border is Dimmit County, one of the top gas producing counties in Texas. Dimmit county has a population of only 10,000, with the agriculture, mining, and municipal sectors being its largest water users. Out of the total projected water demands for 2020, approximately 34% will be used by mining (5,000 AFY), with agriculture using 40% (5,700 AFY) and municipal using 23% (3,400 AFY) (TWDB, 2017). These values are a useful indicator to assess potential groundwater competition, especially considering that pumping for mining only comprised 4% of total county water use in 2009. This drastic increase in water consumption by the mining sector can put stress on a system where water allocations were historically supplying fewer sectors.

Although just outside the Region L Water Planning area, another top oil producer in Texas is McMullen County. McMullen County has one of the lowest populations in the region, just under 800. Municipal water demands only comprise 2% of the water demand. Ninety percent (4,000 AFY) of the water demand is consumed by the mining sector, 7% (350 AFY) by livestock, and the remaining 1% by agriculture (40 AF) (TWDB, 2017). Both mining and agriculture in McMullen County are expected to experience shortages during the TWDB planning period cycle, which runs every 5 years. Although TWDB has made strategic plans to meet future water demands in McMullen County, these projected shortages are a perfect example of groundwater competition impacting other sectors.

Atascosa county is an area of interest because it lies within the Eagle Ford producing region, but unlike other counties, has a growing population exceeding 52,000 residents (TWDB, 2017). Although this county has one of the highest populations in Region L, projected municipal water demand for 2020 is estimated at only 18% of the county's total water demand. This contrasts with Atascosa's agriculture sector, the largest water consumer for the county, where 2020 demands are anticipated to be 60% of the total water demand. For comparison, demand for mining activities in Atascosa is projected to reach 4,000 AFY by 2020, only 9% of the county's total demand, whereas agriculture demand is currently projected at 27,000 AFY (TWDB, 2017).

By comparing the relative ranking of different sectors water demands in these counties overlying the EF, it is evident that counties with the highest percent of water demand for the mining sector also have the lowest populations (near or below 20,000). Even in high oil and gas producing counties such as Karnes, Dimmit, and McMullen, water demand for the mining sector does not exceed 5,000 AFY. This shows that the proportion water demand for mining relative to total demand varies greatly across counties, and that projected mining demand looms large when the population is small or there are no other large industries in the region.

2.3 Regional Groundwater Sources

Aquifer top and bottom elevation, transmissivity and storativity is supplied by the TWDB through Groundwater Availability Models (GAMs) and

Geographic Information System (GIS) data (TWDB-Groundwater Models, 2019). Each GAM is accompanied by a report that describes the aquifer layers, characteristics, and details regarding how each model was constructed and calibrated. GAMs are made as support tools to facilitate planning and development of water management strategies. They are especially valuable in planning for droughts. GAMs are employed mainly by Regional Water Planning Groups, Groundwater Conservation Districts (GCDs), River Authorities, and state planners. Major aquifers within the Eagle Ford footprint are shown in Figure 2-3.

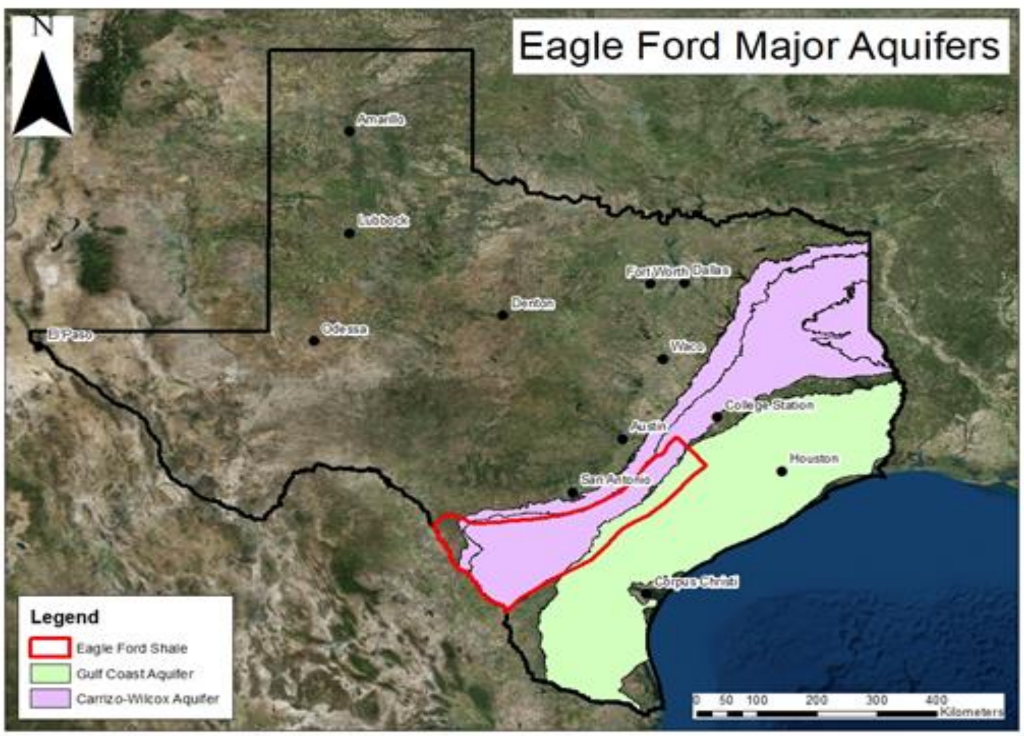


Fig 2-3: Extent of Eagle Ford region in relation to its major aquifer supplies. Note: western and eastern boundaries known to extend past Texas administrative boundary.

2.3.1 Carrizo-Wilcox, Queen City, and Sparta Aquifer System

Consisting of the Wilcox Group and the Carrizo Formation of the Claiborne Group, the Carrizo-Wilcox aquifer is a major aquifer in Texas that stretches from the southernmost regions near the Rio Grande to East Texas, continuing into Louisiana and Arkansas. The Carrizo-Wilcox aquifer lies beneath 66 counties and is ranked third in the state for water usage at 430,000 AFY, behind the Gulf Coast and Ogallala aquifers (Deeds, 2003). The Carrizo-Wilcox aquifer has an outcrop area of over 28,000 km^2 and subsurface area over 65,000 km^2. George et al. (2011) describes the aquifer as primarily comprised of sand that is locally interbedded with gravel, silt, clay and lignite. The aquifer formation reaches a thickness of 900 m but only averages a thickness of 200 m of saturated freshwater. Groundwater typically contains less than 500 mg/L of total dissolved solids (TDS) in the outcrop zone whereas in deeper regions, approximately levels can reach higher than 1,000 mg/L of TDS (George et al., 2011). The Wintergarden region of the Carrizo-Wilcox contains groundwaters that are slightly to moderately saline, ranging from 1,000 to 7,000 mg/L TDS. Irrigation pumping in this area accounts for more than half of the total water pumped, and pumping for municipal supply accounts for approximately 40% (George et al., 2011). Total declines in the potentiometric surface are estimated to reach 100 m in the southern portion overlying the EF, owing to pumping for irrigation.

The Queen City aquifer overlies the Carrizo-Wilcox system and is a minor aquifer resource for the state. The aquifer has an outcrop area over 18,000 km^2

and a similar size in the confined portion (George et al., 2011). The aquifer stores water in sand, loosely cemented sandstone, and clay layers, and has a saturated thickness of approximately 45 m (George et al., 2011). Water quality in the recharge zone can be estimated by TDS levels which average 300 mg/L. In contrast, in the deeper portions TDS averages 750 mg/L (George et al., 2011). The primary water uses for the Queen City aquifer are for livestock and domestic purposes, but municipal and industrial uses are more significant in northeast Texas. Water levels in the Queen City aquifer vary by region. Water decline from pre-development conditions range from 2 to 40 m in the southern portion of the aquifer and 3 to 21 m in the central portion of the aquifer (George et al., 2011).

Above the Queen City Aquifer is the Sparta Aquifer, comprising a part of the Claiborne Group. Characterized by sand interbedded with silt and clay layers, the Sparta aquifer underlies below 25 counties, and has an outcrop area of 3,900 km^2, whereas approximately 18,000 km^2 is confined (George et al., 2011). The saturated thickness of the aquifer averages 35 m but ranges from 215 m in the north to 60 m in the south (George et al., 2011). The TDS in shallow parts of the aquifer are approximately 300 mg/L, but increases to 800 mg/L with depth. Water is pumped primarily for livestock and domestic purposes, with marginal demand from the municipal, industrial, and irrigation sectors in areas such as Houston and Brazos counties. There has been no significant declines in the potentiometric surface in the Sparta Aquifer (George et al., 2011).

2.3.2 Gulf Coast Aquifer System

The Gulf Coast Aquifer System is composed of three primary aquifers, the Chicot, Evangeline, and Jasper aquifers. This aquifer system extends from Louisiana following the Gulf of Mexico coastline and continues south into Mexico. The aquifer system covers an area over 106,000 km^2 and underlies 54 counties. The aquifers are composed of laterally discontinuous deposits of gravel, silt, sand, and clay, reaching thicknesses of 215 m in the southern region and 400 m in the northern region (George et al., 2011). Over the entire aquifer, its freshwater saturated thickness averages approximately 300 m. George et al. (2011) reports that water quality varies by region, but is generally less than 500 mg/L TDS. TDS levels are reported to increase towards the south, reaching levels between 1,000 and 10,000 mg/L. This occurs in areas where aquifer productivity decreases. In the areas overlying the EF, the aquifer is utilized primarily for municipal, industrial, and irrigation purposes.

2.4 Eagle Ford Shale Water Use

The relative proportion of water sources used to oil and gas development vary throughout the region. These sources are groundwater, surface water, and recycled water. The semi-arid climate overlying the EF results in limited surface water resources. Therefore, energy developers have relied on groundwater to supply HF. Approximately 90% of water used for HF in the EF is estimated to come from groundwater. The remaining 10% of supply is derived from recycling of flowback and produced water, which are secondary water flows. These waters are often highly saline and begin to be produced shortly after a HF treatment and continue throughout the oil and gas producing lifetime of a well (Steadman et al., 2015). The relative reliance on groundwater for HF may change in the future as technological advances make recycling more feasible. This study, however, will focus on the current use of groundwater for HF.

Freyman (2014) stated the EF provided minimal volumes of flowback water. Therefore, the potential of treatment and reuse of flowback water in HF in the EF region is limited. This has led to the use of brackish groundwater as an alternative to freshwater. In 2014, brackish groundwater use in HF in the EF was estimated to comprise 20% of total groundwater use. This proportion is expected to increase as frack water technology advances (Freyman, 2014). Technological advances in horizontal well lengths, however, require more water as the number of fracture stages increase (Nicot, 2012). A fracture stage is a portion of the horizontal oil and gas well that is sectioned off and fracked. The process of HF is performed through many fracture stages. The number of stages increase with well length.

Although on a statewide scale water use by HF appears minimal, the local impacts on water supplies needs to be studied further to understand how it may affect people, businesses and municipalities in other sectors pumping from the same aquifer. Showing how this statewide statistic can be misleading, Scanlon et. al (2014) reported that water demand for HF in the EF area comprises approximately 16% of the total water consumption in this region. In a region that experiences frequent droughts and water scarcity, this is not an insignificant amount of new water demanded by HF. Furthermore, there is a projected water demand of 1.2 billion m^3 to frack 62,000 anticipated oil and gas wells over the next 20 years. This is much more than past EF water uses totaling only 0.018 billion m^3 between 2008 to 2011 (Nicot, 2012). Within the region, 65% of consumed water is towards irrigation purposes. This is followed by 12% for municipal use and 13% for steam electric power generation (Scanlon et al., 2014). Adding to previous TWDB projections of water demand, Scanlon et. al (2014) found annual HF water demand ranged from 1 to 27% of the total aquifer freshwater storage at the county level.

As part of a study to quantify water-related risk (i.e., any water related challenge including water scarcity, flooding, drought), researchers at the World Resources Institute (WRI) constructed global and regional maps depicting water stress (Gassert et al., 2013). Gassert et al. (2013) defined water stress as a region's total annual water withdrawals divided by its total annual available blue water. Blue water is defined as the total renewable water available in a year before satisfying any use. Calculated water stress was then divided into a baseline water stress index classified as the following, 1) Low stress (0-1), 2) Low to Medium stress (1-2), 3) Medium to High stress (2-3), 4) High stress (3-4), and 5) Extremely high stress (4-5).

Using the classifications from Gassert et al. (2013), Freyman (2014) reported 98% of oil and gas wells within the EF were in areas classified by as

“Medium to High” water stress or greater. For example, 28% of these wells were located in “High” to “Extremely high” water stress (Freyman, 2014). Baseline water stress defined in Gassert et al. (2013) is shown for Texas in Figure 2-4. Dimmit, La Salle, Karnes, Webb, McMullen, Gonzales, DeWitt, Atascosa, Live Oak, and Zavala County are some of the highest HF water using counties within the play (Freyman, 2014). Freyman (2014) reports that Karnes, Gonzales, and DeWitt stand out as having the highest risks of water stress, out of the 10 counties overlying the EF. This potential competition sets the stage for possible grievances between water users and may cause water shortages or water supply cost fluctuations in the pursuit to produce groundwater.

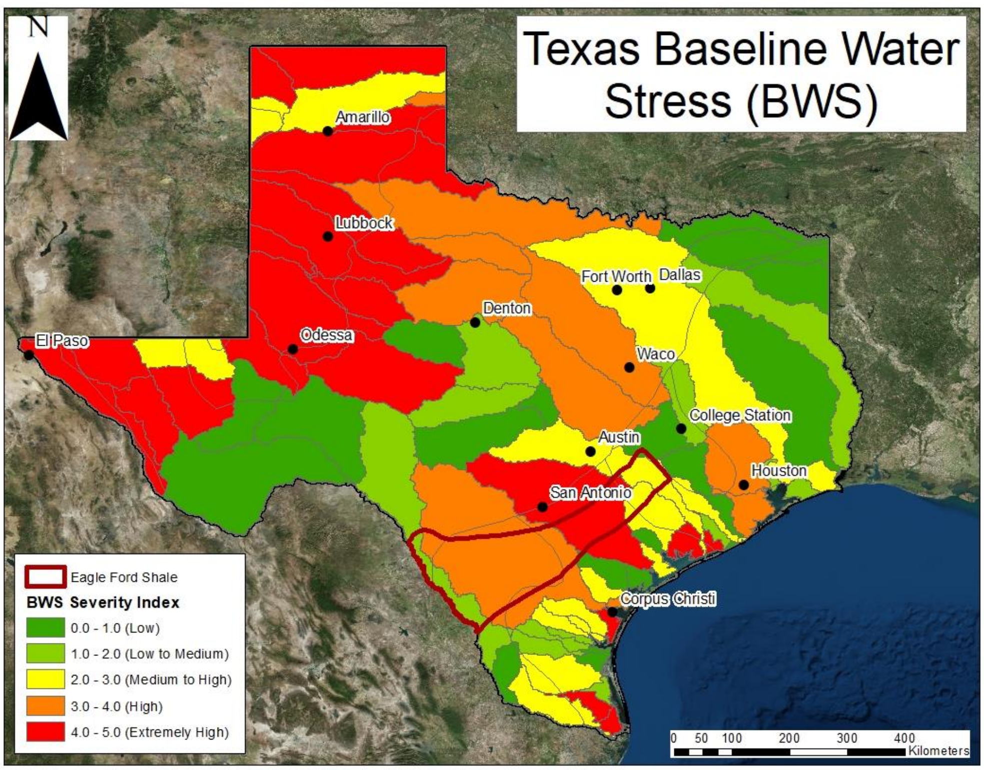


Fig 2-4: Baseline water stress defined by Freyman (2014) for Texas.

Current analysis of HF well intensity, or the volume of HF water used per meter length of an oil or gas well, reveals a steady increase of water use at about 18.6 m^3/m (Ikonnikova, 2017). As average lateral well lengths have increased from 1,310 m in 2010 to 1,770 m in 2016, the total water use per well has increased from 16,000 m^3 to 33,000 m^3 (Ikonnikova, 2017 & Nicot, 2012). Ikonnikova (2017) added a key indicator to predict water usage that was not addressed by Nicot (2012), in which she considered the variability in oil and gas prices and its linear correlation with the number of wells drilled to estimate HF water use throughout the region. Using a price scenario window of $30/bbl to $100/bbl, the resulting HF water demand projected to the year 2045 was estimated to range from 4.2 to 19×10^8 m^3 (Ikonnikova, 2017). In more economically productive areas of the Eagle Ford, water use for HF averaged 28,000 m^3/well, in contrast to 25,000 m^3/well in the less productive areas.

Ikonnikova’s study incorporated variables that were either not included in past studies or the values of the variables were unavailable owing to lack of historical data. These new variables included choice of well location based on price projection, geologic and petrophysical reservoir characteristics, the utilization of a production-decline curve model, and the availability of longer historical well data. Using the EF as the study region provided several advantages for the investigation, including access to 7 years of data that encompassed production over both low and high energy prices and a relatively widespread geographical data coverage, covering approximately two-thirds of the play area.

Ikonnikova (2017) found that HF water use was correlated with both the pressure and oil gravity characteristics of a well, proving that certain areas of the EF are more water intensive than others based on the geology of the shale formation and its profitability index. These characteristics, coupled with varying levels of oil and gas production which is dependent on location within the region, affect the overall profitability of an oil and gas well. With this understanding, intense water use is expected to occur in areas where low production expenses are coupled with both high quality and quantity oil and gas, increasing overall profit. From these results, specific areas within the EF can anticipate water use intensity changes in response to fluctuating energy prices, potentially exacerbating local groundwater competition.

2.5 Eagle Ford Oil and Gas Production

Production in the EF initiated in 2008 but did not fully commence until approximately 2011. During this time gas production more than doubled and oil production increased six-fold, making the EF one of the most active drilling areas in the world (Eagle, 2016). By 2016 the EF was supplying about half of the total U.S. crude oil production, at $5x10^6$ barrels of oil per day (bbl/day) (Ikonnikova, 2017). For natural gas production, EF is reported as the second largest shale gas producer in the U.S. behind the Marcellus shale, accounting for nearly 12% of all domestic shale gas production (Hughes, 2015).

Oil and gas production peaked in March of 2015, following the decline of oil prices that began in June of 2014 (Hughes, 2015). During peak production the play was producing 1.61 million barrels of oil per day (mbd) and 6 million cubic feet of gas per day (bcf/d). Even during the oil price collapse the EF remained one of the more resilient plays in the U.S., continually producing more oil than any other domestic play (Hughes, 2015). By 2015, there were over 15,500 producing wells in the EF and approximately 21,000 drilling locations remaining for further development (Hughes, 2015). The EF has been estimated to hold 3.4 billion barrels and 55.4 trillion cubic feet (Tcf) of technically recoverable shale oil and gas (EIA, 2011 & Hughes, 2015). Given this prediction, Hughes (2015) predicted that by the year 2040, the EF will continue to rank within the top five U.S. oil and gas producing region (Hughes, 2015).

A typical gas well is expected to produce a minimum of 4 billion cubic feet (Bcf) during its lifetime, given the average estimated ultimate recovery (EUR) per shale production well. This term is an approximation of the quantity of potentially recoverable oil and gas. At maximum well lifetime production, 6 Bcf was reported by Talisman Energy, Rosetta Resources, Murphy Oil Corporation, and Petrohawk Energy in a review of domestic shale plays by the Energy Information Administration (EIA, 2011). Companies also reported varying average EURs between different production zones, with 300 million barrels of oil (MBO) for the oil zone, 4.5 Bcf for the condensate zone, and 5.5 Bcf in the dry gas zone during a production well lifetime (EIA, 2011). Represented in Figure 2-5, these zones characterize the levels of hydrocarbon maturity within a formation, which are often characterized by a gas-to-oil ratio.

An investigation of oil and gas production in the Eagle Ford found that the average lifetime of a well was approximately 30 years, however, its total production was found to be drastically reduced within the first few years (Wachtmeister, 2017). Initial production (IP) levels, commonly used synonymously with peak production rates, averaged 500 (bbl/day), followed by mean annual declines of 74%, 47%, and 19% in oil/gas production during the first, second, and third year of production, respectively (Wachtmeister, 2017). By the third year of production, the remaining production level relative to IP level had diminished to 11% (Wachtmeister, 2017). This study used a 12-month average production rate to define a cutoff for when wells would fall below an average production of 4 bbl/day (Wachtmeister, 2017). From this study's logic it can be assumed that after approximately 30 years and at that consistent production rate, continuing production from a well becomes uneconomical, after which a company would respond by plugging the well permanently.

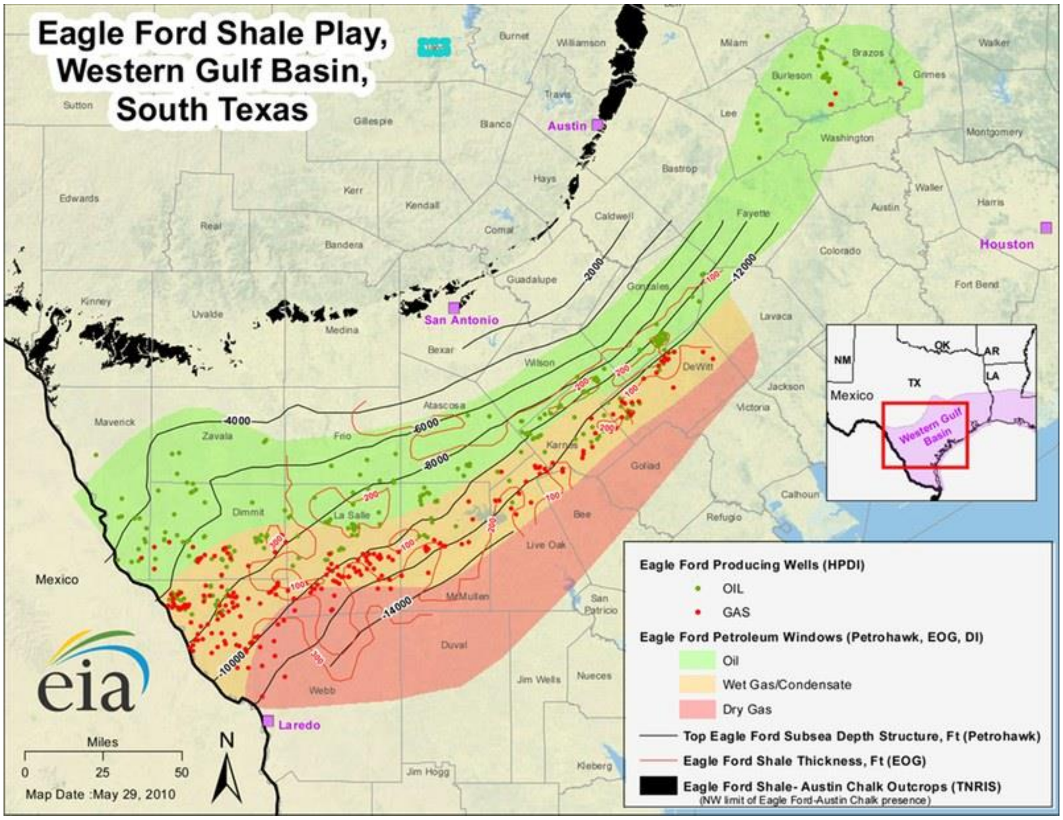


Fig 2-5: Eagle Ford Shale oil and gas production type zones. Oil and gas wells that were actively producing in May of 2010 are indicated in green and red points. Reprinted from the U.S. Energy Information Administration (available at: eia.gov/maps/)

2.6 Impacts of HF Activities & Production in the Eagle Ford

When investigating the impacts caused by the exploitation a natural resource, in this case oil and natural gas production facilitated through hydraulic fracturing, the theory of the “resource curse” needs to be kept in mind when weighing the positive and negative impacts. In its broadest definition, the resource curse is the idea that the relationship between the exploitation of an abundant natural resources and the economic, political, social, and environmental development of a region are inversely related (Hasapidis, 2015). By developing a natural resource, in some cases this may lead to long term depressed economic growth, increased political fragility, decreased social investment, and lowered quality of the environment.

Many studies uncovering evidence in support of the existence of the resource curse have focused on developing countries in Asia, South America, and Africa. The risk of the resource curse in the U.S., and more specifically the EF is difficult to assess. Reasons for this obscurity include the migratory nature of workers, the non-uniformity of economic growth, and the local-scale variability that can exist within geographic and political boundaries, to name some (Tunstall, 2015). The goal of the following sections is not to prove or disprove the natural resource theory in the EF, but to integrate the research and results of past studies to provide a balanced description of impacts so that this study can add to our holistic understanding of the costs and benefits. In cases where site-specific data or research regarding the broad array of impacts are limited, national studies or general information is provided as a substitute.

2.6.1 Economy

2.6.1.1 Economic benefits

Texas is a noteworthy state in regards to fossil fuel development and administration in the U.S. This is demonstrated through: 1) the state's regulatory organization by the Railroad Commission; 2) a system of well-defined mineral rights; and 3) a network of "bottom-up", local regulatory districts governing groundwater use (Tunstall, 2015). Texas produces all phases of oil and gas, offering residents like those in the EF the opportunity to participate in upstream, midstream, and downstream economic activities spanning the entire supply chain. Compared to other U.S. states, Texas is home to many more refineries that generate additional jobs beyond primary oil and gas extraction (Tunstall, 2015).

Combining the economic impacts of EF development through the years 2014 to 2016, Oyakawa et al. (2017) summarizes economic impact by estimating the total revenue output, full-time-equivalent jobs supported, total payroll (salaries and benefits) to workers, gross regional product (value added), and state and local government revenues (Table 2-1). These findings are in agreement with economic development reported by Sovacool (2014) in which similar benefits have been derived from the development of other domestic shale plays. Using a total of nine indicators spanning subjects on industry specialization, growth, and worker productivity, Oyakawa et al. (2017) reported the different industry types that grew and/or moved into the EF region between the years 2009-2014.

Findings revealed a high growth rate of support industries in oil and gas operations, including petroleum refining and pipeline construction. Other industries like leather/hide tanning and fishing, poultry and egg production, cotton farming, seasoning and dressing manufacturing, and vegetable and melon farming also showed substantial growth. Oyakawa et al. (2017) notes this expansion may not be dependent on local demand but rather indicates an increase of selling outside the region. Industries not partaking in any exporting that grew include concrete manufacturing, health care services, printing, and recreational activities.

The final group of industries identified by Oyakawa et al. (2017) are ones that did not exist in 2009 but were present by 2014, showing a movement of new industries into the region coinciding with development of the EF during this time. These industries include organic chemical manufacturing, housing, commercial and service industry machinery manufacturing, and power boiler and heat exchange manufacturing (Oyakawa, 2017).

Combining all of the economic growth within the EF, it is evident that development is not only occurring in response to the oil and gas production, but also due to the continuous flux of employees moving into the region. These findings are in agreement with Betz et al. (2015), in which these economic impacts were compared to coal mining and found more beneficial in the long run. In the same study, Betz et al. (2015) reported oil and gas developments promoting more direct regional profits, divergent from industry growth, citing royalty and lease payments to residents directly in ownership of proposed production sites. These payments can significantly increase the per capita income of a region, however, it is important to note that these benefits are not guaranteed to extend to raising local wages and median household incomes (Betz, 2015). Betz et al. 2015 acknowledges more variable impacts from oil and gas development, stating there is an assertive construction phase preceding production, usually to establish road infrastructure and pipeline networks to keep up the growing number of rig sites. This development was found to greatly slow down after its initial phase, but oil and gas production remained high (Betz, 2015).

Table 2-1. Estimated economic impacts for the main 15-county area in the Eagle Ford Shale for 2014, 2015, and 2016. Reprinted from Oyakawa et al. (2017).

Estimated impacts for Eagle Ford Shale at the 15-county Level EFS (2014)				
Economic impacts in millions of dollars				
	Direct	Indirect	Induced	Total
Output	$84,318	$10,583	$3,114	$98,014
Employment, full-time equivalent	36,893	69,596	23,963	130,451
Payroll	$2,146	$2,147	$709	$5,002
Gross regional product	$36,722	$5,164	$1,698	$43,584
Estimated local government revenues	$0	$0	$0	$1,590
Estimated state revenue, incl. severance taxes				$3,042

Estimated impacts for Eagle Ford Shale at the 15-county Level EFS (2015)				
Economic impacts in millions of dollars				
	Direct	Indirect	Induced	Total
Output	$50,653	$6,176	$2,060	$58,890
Employment, full-time equivalent	25,494	38,724	15,725	79,944
Payroll	$1,402	$1,251	$469	$3,122
Gross regional product	$21,235	$3,008	$1,103	$25,346
Estimated local government revenues	$0	$0	$0	$1,413
Estimated state revenue, incl. severance taxes				$2,202

Estimated Impacts for Eagle Ford Shale at the 15-county Level EFS (2016)				
Economic impacts in millions of dollars				
	Direct	Indirect	Induced	Total
Output	$29,021	$3,037	$1,221	$33,278
Employment, full-time equivalent	9,324	17,406	9,404	36,135
Payroll	$855	$593	$283	$1,731
Gross regional product	$12,327	$1,494	$653	$14,473
Estimated local government revenues	$0	$0	$0	$1,011
Estimated state revenue, incl. severance taxes				$1,506

In an inter-disciplinary study of the economic, social, and environmental impacts of energy production in the Eagle Ford, Mohtar et al. (2019) models five example scenarios based on two discrete approaches of either estimated oil and gas prices or expected production increase, with an added component of two technological advancement options. Following the five model scenarios reported in the study, estimated total tax revenue for the region ranged from $378 million to $6.9 billion, with indirect revenues (i.e. sales taxes) from $504 million to $3.14 billion. Employment and average total wages were estimated at 4,500 to 15,540 workers, summing an income range of $39 million to $135 million (Mohtar, 2019).

2.6.1.2 Economic drawbacks

While many of the economic benefits from shale energy production and hydraulic fracturing are tangible, there are costs and uncertainties that come with this capitally intensive and technologically complex industry. Although hydraulic fracturing has been a production technique for over six decades, its rise in popularity within the last decade to compensate for depleting conventional reserves leaves little continuous data to understand the long-term economic effects. One argument made by the natural resource curse theory is that regions with abundant natural resources have much slower economic development compared to regions with little natural resources. However, at least in the U.S. and EF, many of the negative economic impacts of hydraulic fracturing stem from the volatile, unclear nature of energy production. In most cases this results in rapid, possibly uneven development of a region, but is development nonetheless.

Possibly counterintuitive, given the quantity of investments in domestic shale production, the total cost of hydraulic fracturing is proving to result in net losses for most oil and gas companies due to the added expenses of continuous exploration (Kee, 2017). Despite these deficits, companies must continue to explore today to produce oil and gas for tomorrow. This quality of shale production exemplifies what is described previously regarding steep production decline curves for EF wells.

Adding to the issue of steep production decline, uncertainty related to measuring proven oil and gas reserves in a shale field is proven to vary drastically between studies. Sovacool (2014) compiled shale reserve estimates from 3 prominently cited studies, one in 1997 by H.H. Rogner, a 2011 assessment by the U.S. Energy Information Administration, and a 2012 assessment by ICF International (ICF). Comparing all three estimates of total reserves revealed a global difference up to 60 %, with regional reserve estimates conflicting by 400 to 500 % (Sovacool, 2014). Sovacool (2014) reported the 2011 U.S. Geological Survey (USGS) assessment of reserve estimates for the Marcellus shale region to grossly conflict with results reported by the Department of Energy (DOE) that same year, showing a 5-fold overestimate by the DOE compared to the USGS report. Closely following this incident, the DOE report was revised in which projected natural gas reserves were lowered from 410 tcf to 141 tcf, a two-thirds reduction (Richmond, 2012). The uncertainty of these shale reserve estimates dampen the confidence of future oil and gas production. This may become increasingly evident when highly productive "sweet spots" of a shale formation become depleted.

Relating back to high operational costs of hydraulic fracturing and production, and steep production decline, the ability for companies to make a profit relies heavily on current oil and gas prices (Sovacool, 2014). This requires a large amount of capital from the industry to maintain production, calling for a constant inflow of new wells drilled just to maintain stable production levels. In a report published by the Post Carbon Institute in 2013, Hughes estimated the capital costs of a production well in the Haynesville shale gas play around $9 million at 2012 market prices. To keep production level, drilling would require 800 new wells and cost approximately $7 billion a year, excluding the indirect costs of leasing, infrastructure, and royalties (Hughes, 2013). At a national scale this means $42 billion was needed to offset the decline in production, in which shale gas generated $33 billion in revenues, a relatively strained window for overhead profit (Sovacool, 2014). While consumers enjoy low energy prices, the government and industry need to acknowledge that oil and gas prices must increase to keep production constant, a variable difficult to control and dependent on many social and economic factors both domestic and global. This confirms the long-term sustainability of shale production questionable, already foreshadowed by the fact that 70 % of U.S. shale gas production originates from plays either flat or in decline (Hughes, 2013).

2.6.2 Environment

2.6.2.1 Environmental Benefits

Arguably the most significant environmental benefit from hydraulic fracturing and shale production is the drastic reduction in emissions of carbon, sulfur oxides, nitrogen oxides, and mercury associated with burning natural gas compared to coal (Sovacool, 2014). With a cheap and abundant supply of shale gas, coal has been largely replaced as an energy source. As a result, power plants release up to 50 % less greenhouse gas emissions into the atmosphere and HF operations are significantly less destructive than coal mining (Engelder, 2011). Researchers from MIT created energy scenarios for the U.S. projecting varying levels of shale gas growth and usage to estimate changes in greenhouse gas emissions (Jacoby, 2012). Using the 2012 shale outlook which projected a 13 % increase from the year 2005 to 2050, the model indicated a 17 % reduction in national greenhouse gas emissions, compared to energy production without shale oil and gas (Jacoby, 2012).

From a government standpoint, replacing coal with natural gas as a means to satisfy greenhouse gas reduction goals has been a major priority for policy makers. However, although emissions are significantly lowered relative to coal, scientist and government officials emphasize that its use is only a means to prolong economic and environmental stability until renewable and nuclear energy can supply more energy demands (Sovacool, 2014).

2.6.2.2 Environmental Drawbacks

Studies on the environmental degradation from hydraulic fracturing and surrounding activities seem to draw the focus away from the benefits of decreased greenhouse gas emissions. At a national level, shale oil and gas development has been attributed to a decrease in local air quality, groundwater and surface water pollution, depletion of water resources, induced seismicity, deterioration of land and road infrastructure, and noise and light pollution (Sovacool, 2014). It is important to note that every shale play has a unique economic, geologic and social setting. Therefore, the management of environmental impacts will differ from one region to the next.

Environmental concerns from residents in Gonzales and Karnes County were surveyed and published by Adeoye (2017). From the survey, local residents expressed concerns regarding water quality, air quality, the release of fracking chemicals and other pollutants, soil quality, unregulated water runoff, and competition with limited water sources (Adeoye, 2017). A majority of these concerns align with the current state of published studies in the EF. Therefore, these results can be thought of as fairly representative for the entire region.

There have been two major site-specific studies regarding groundwater quality in the EF region with implications towards oil and gas activities. Hildenbrand et al. (2017) conducted analyzed the water from 77 private water wells in the EF region. They found two distinct sample populations which were differentiated based on their bromide/chloride ratios. Oil brines are known to have high bromide/chloride ratios (McMahon et al., 2017). Further chemical analysis revealed elevated levels of fluoride, nitrate, sulfate, various metal ions, and volatile organic compounds (VOCs) in samples with high bromide/chloride ratios (Hildenbrand et al., 2017). Combining the results from chemical analysis with well properties (depth, location, clustering, spatial relation to oil and gas wells) led Hildenbrand et al. (2017) to conclude that while there was evidence of sporadic contamination events possibly connected to unconventional oil and gas development or other anthropogenic activities, groundwater quality was predominantly controlled by natural processes. Sources of contamination were difficult to specify given elevated levels of bromide could have originated from both gasoline and pesticides, however, the sporadic detection of VOCs with observed dissolved gas effervescence provided some evidence in support of influence from nearby oil and gas development (Hildenbrand et al., 2017). These somewhat contradictory results are what led Hildenbrand et al. (2017) to conclude that more years of testing are needed to obtain more solidified evidence on the possible sources of groundwater contamination.

More recently, drinking water wells in the EF were tested for methane and benzene as part of a larger study that included wells in the Fayetteville and Haynesville shale plays (McMahon et al., 2017). Although 81 % of EF samples contained methane concentrations greater than 0.001 mg/L, only 7 % of the samples exceeded concentrations greater than 10 mg/L, a proposed action level for methane in groundwater (McMahon et al., 2017). Benzene concentrations exceeding 0.013 μg/L were detected in 9.3 % of the EF water samples and were present in more varied water types and TDS ranges than methane occurred (McMahon et al., 2017). This study found methane and benzene detections weakly correlated in EF samples, but a pattern of higher benzene concentrations in wells in the vicinity of older, conventional wells. Given the groundwater travel time of regional aquifers, McMahon et al. (2017) concludes that decades or longer may be needed to accurately assess the impacts of subsurface and surface hydrocarbon releases on the water wells used in the investigation.

Water availability in the EF is a vigorously studied subject given the water intensive nature of hydraulic fracturing and the region's dry climate. While EF groundwater availability and use are described in Section 2.4, the topic of groundwater competition brought up by surveyed residents in Adeoye (2017) is an integral component of this study that is best represented in Figure 2-6. Figure 2-6 displays 3 pumping wells, all within close proximity to one another and pumping concurrently. Depending on the duration of pumping, volume intensity, and well screen depth, the drawdown extent, or cone of depression, formed from one well can expand into another well's cone, coincidentally influencing the availability of groundwater at the well site. Given the conceptual model that a neighbor can pump so much water to potentially decrease the availability to surrounding wells, the common notion of "use it or lose it" can be used to characterize groundwater competition. This highly local and time dependent form of groundwater competition is a phenomenon this study aims at addressing.

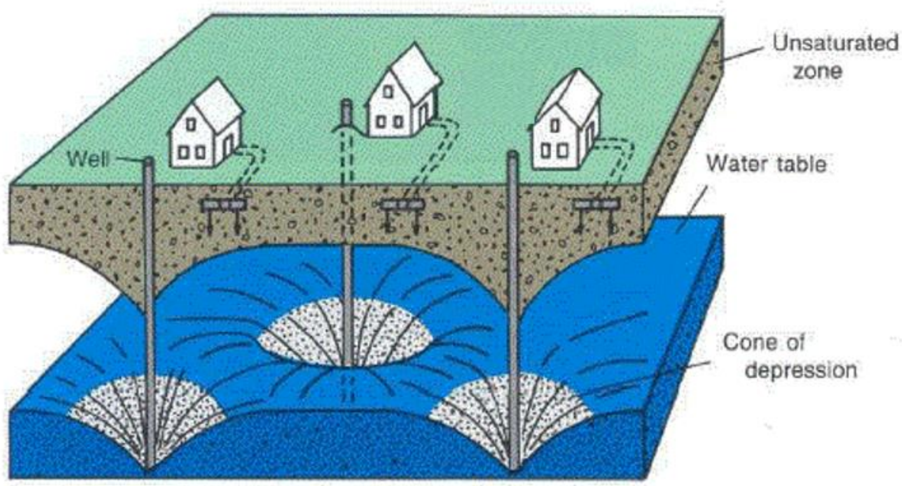


Fig 2-6: Conceptual model of aquifer drawdown induced from pumping. Overlapping cones of depression are capable of affecting groundwater availability to neighboring residents. Reprinted from Waller, R.M. (1994).

Adding to Freyman (2014) and Gassert et al. (2013), water stress related to HF was examined at the global scale by Rosa et al. (2018). Rosa et al. (2018) applied a water balance model to shale deposits around the world to predict the impacts of HF on local water availability to other human uses and ecosystem functions. In the study, the authors made an important distinction between “water stress” and “water scarcity”. Whereas water scarcity refers to the volumetric lack of water, water stress (briefly described in Section 2.4) encompasses water scarcity but with several added physical attributes to describe its ability to meet needs. These include water quality, accessibility, and affordability (Rosa et al., 2018). As part of the water balance calculation, Rosa et al. (2018) quantified water stress as the ratio of local water consumption by human activities (i.e., municipal, agriculture, mining, and other industries). Model results with energy production scenarios indicated that the EF region is not only predominantly water stressed, but also displaying the highest calculated water stress index value over 5, signifying extreme unsustainable water consumption (Rosa et al., 2018). These findings coincide with projected sectoral water demand described in Section 2.2 and validate the concerns regarding increased competition for local water resources.

2.6.3 Society

2.6.3.1 Social Benefits

The social benefits of unconventional oil and gas can be directly tied to the economic benefits described earlier in the chapter. These benefits include residents receiving increased employment opportunities, increased wages, heightened property values, and revived communities from industry investment. These economic benefits have the capacity to drastically improve the standard of living for individuals and populations residing in regions with unconventional oil and gas production. Attributed in part to the abundance of shale oil and gas production, the state of Texas and the U.S. as a whole experience the benefit of energy affordability. Independent of an individual's location relative to a shale play, domestic oil and gas prices are markedly lower than in countries like Japan and Germany where energy production is much lower (Sovacool, 2014). Lower oil and gas prices can improve the standard of living even in the smallest respects of social well-being. For example, low gas prices decrease the cost of travel and the price of amenities made from fossil fuels.

2.6.3.2 Social Drawbacks

Similar to the connection between social and economic benefits of unconventional production in the EF, social drawbacks can often reflect the consequences of environmental degradation. Human health and well-being are directly related to environmental health, which often serves as the motivation for disgruntled citizens when reporting complaints. A significant detail while investigating the negative social impacts of HF in the EF is that they are almost entirely seen at the local scale of production, bringing into question whether the benefit of many outweigh the harm of a few (Barajas, 2011). In an effort to remain relevant while still discussing significant issues faced in the EF, this section will shortly detail air quality, a highly reported issue in the region, and will go more in depth on the impacts that HF has had on groundwater from a social perspective.

While only briefly mentioned as a negative environmental impact of HF, air quality degradation has been one of the largest issues affecting the health of residents in the EF (Oil, 2014). Common emissions from drill sites include VOC and Nitrogen Oxide emissions, which combined with sunlight forms ozone (O_3) and reportedly causes adverse effects to lung tissue. Noxious hydrogen sulfide gas is another emission with a significant number of complaints in the EF, often causing eye and throat irritation, dizziness, and even unconsciousness in a matter of minutes of exposure (Boman, 2013). One study gathered every oil and gas related complaint reported from 2010 to 2013 to the Texas Commission of

Environmental Quality and revealed almost 300 complaints were filed within the EF region (Song et al., 2015). Counties with the highest number of complaints include Karnes, Atascosa, Gonzales, and Frio county, with a majority of the complaints related to air quality and subsequently waste release quality (Song et al., 2015). In addition, Song et al. (2015) revealed homeowners in the EF can dwell in close proximity to production facilities. Of the two homeowners that participated in the report, both lived less than 3 miles from a facility and were allegedly experiencing adverse health impacts from production activities (Song et al., 2015).

While there is limited published research quantifying the social impacts HF in the EF has on local groundwater resources, there are many statewide accounts from locals who illustrate dreary consequences from sudden surges of groundwater use as energy development embraces towns. One example of this is in Barnhart, Texas, a small town located on the eastern edge of the Permian Shale Basin. Energy production gained momentum in 2011 and by 2013 the small community had reportedly run out of water (Goldenberg, 2013). The local water supply company of Barnhart struggled to develop new groundwater sources for the public due to insufficient funds, forcing residents into water rationing restrictions (Goldenberg, 2013). Goldenberg's reporting of Barnhart revealed cotton farmers were losing up to half of their crop yields and many ranchers were forced to sell off large portions of their herds to make up for limited water supply. While these operations, some over 30 years old, attributed recent energy development for their demise, one cannot ignore this phenomenon as a product of antecedent overuse by ranchers, farmers, growing cities, and climate change (Goldenberg, 2013). Adding more stress to the situation, tensions between townspeople grew as some residents were forced out of their livelihoods due to a lack of water while their neighbors were making profits from selling their water to HF companies, even during water restrictions (Goldenberg, 2013).

There are key similarities between Barnhart and towns in the EF that pose a risk for similar consequences. Towns in the EF can be as small as a few hundred residents, reliant on agriculture and livestock operations. With a small population base to fund public utilities, municipal water suppliers are given little financial resiliency in the case of acute water shortages. In areas with a higher population density, like Karnes county, there may be more available funds to respond to water shortages but the severity of competition can be amplified and more widespread. Recalling how homes in a close vicinity to production sites commonly experience air quality issues, the same framework can apply to water supply wells that are nearby to HF supply wells. Not only can a resident or entity experience a dry well that in turn requires more costly investments, but in some cases well owners take legal action against the local GCD responsible for permitting the well that is blamed for mal-effects. This action adds more social unrest to the issue and only shifts the financial burdens to the GCD, where it is not uncommon to see operations already strained under limited manpower and resources.

2.7 Texas Groundwater Management

By acknowledging that the addition of new groundwater users to a system will inherently increase stress on existing users, one can gain an appreciation for those in positions responsible for managing and upholding the complex balance between the physical processes and legislative rights regarding groundwater. From previous sections it has been concluded that water stress in response to HF is a highly localized conflict that can have radical effects on concentrated populations. Keeping this concept in mind, the following section will focus on summarizing where groundwater use for HF fits into the multi-objective water management framework of Texas and how authority is executed at the local scale.

2.7.1 Rule of Capture

Texas recognizes 3 broad categories of water that are each managed by their own legal regulations: 1) surface water; 2) surface runoff; and 3) percolating groundwater (Eoh, 2014). The interaction and movement of water between categories is recognized, allowing for the interchanging of legal frameworks to be applied when appropriate. While surface water is governed as state property, groundwater is considered a private property to whoever owns the surface estate (Eoh, 2014).

Serving as a precedent for all groundwater law and management in Texas is the Rule of Capture, originating from British common law. Under this doctrine, a surface estate owner holds the right to both produce and sell all of the groundwater that can be pumped within the boundaries of their property, whether or not this pumping creates adverse effects to surrounding neighbors. Due to this seemingly explicit definition, Texas groundwater law is often revered as the "law of the biggest pump" and offers no legal protection to any user (Kaiser, 1987). However, beginning in the 1949, legislation has since been created through various common law, state law, and regulatory agencies that limit the capacity of Rule of Capture and a property owner's right to withdraw groundwater (Eoh, 2014). Revised surface estate owner rights are summarized as follows: 1) pumping must not be done with malice intent towards an adjoining neighbor; 2) pumping must not be done for a wasteful purpose; 3) pumping must not cause land subsidence on adjoining land; and 4) a well may not be drilled to cross property limits (Eoh, 2014). As part of this 1949 legislation, Chapter 36 of the Texas Water Code was passed authorizing the creation of local regulatory frameworks called GCDs. Under Chapter 36, GCDs are given regulatory authority to interpret these revised groundwater pumping statutes while still recognizing a surface estate owner's legal right (Connelley, 2009).

In the context of oil and gas operators seeking to develop a water well to supply for HF, ownership of water rights can be designated in two ways: 1) an operator buys property with the legal right to produce groundwater under the management of a GCD; or 2) an operator is leasing property, in which permission from the owner to develop a water well is required. Either way, obtaining the consent to produce groundwater is often an efficient process requiring administrative fees and paperwork for the GCD. For as long as a person or entity owns the property rights, their ability to produce groundwater cannot be barred or discriminated against. The pumping rate and quantity for a well, however, falls within the discretion of the GCD while still preserving the owner's property rights and production demands.

2.7.2 Groundwater Conservation District Oversight in Oil/Gas Activities

While GDCs act as the local authority to well owners, it is important to understand the planning and management duties they assume that feed into the greater scheme of Texas water planning. Major GCDs within the Eagle Ford Shale area are shown in Figure 2-8. Groundwater Conservation Districts are required to develop and adopt management plans that fit with regional and state plans, adopt and enforce rules in conjunction with the plan, manage well records, permit wells, and establish administrative and financial procedures for the local district (Texaswater, 2014). Goals of GCD management plans are to: 1) provide for the most efficient use of groundwater; 2) control and prevent subsidence and the waste of groundwater; 3) address conjunctive surface water and other natural resource issues; and 4) address drought conditions and conservation of groundwater (Texaswater, 2014). GCD management plan goals are influential in the creation of GCD rules, which vary between GCD and often reflect local priorities. While briefly discussed earlier, this section will more thoroughly detail the authority and roles of GCDs in regard to HF in the EF.

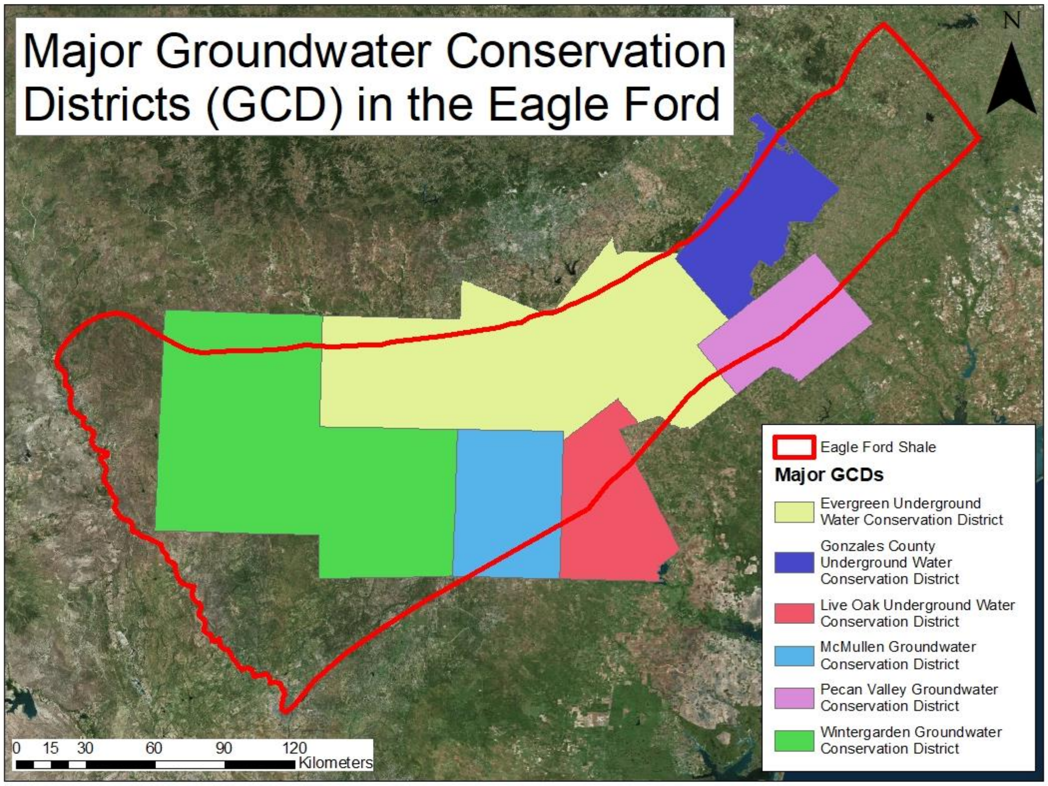


Fig 2-7: Major GCDs managing grounding in the EF.

Concerning water use in oil and gas operations, each GCD applies regulations based on whether the well type is classified as either a rig supply or frack supply well. The distinction between these two well types is still frequently disputed, with the difference determining if a well will be exempt from certain permit requirements, well spacing requirements, production limitations, reporting requirements, and fees. An important detail to keep in consideration, however, is that a well’s classification between rig and frack supply can change at the discretion of the owner. Switching between well classifications is not uncommon and can occur in instances where an operator initially drills a well for rig supply purposes but is later required to change its classification to frack supply once their intended use changes. Switching classifications is inexhaustible, as long as the proper requirements are followed for each.

Section 36.117b of the Texas Water Code regarding exempt wells states: “drilling a water well used solely to supply water for a rig that is actively engaged in drilling or exploration operations for an oil or gas well permitted by the Railroad Commission of Texas provided that the person holding the permit is responsible for drilling and operating the water well and the water well is located on the same lease or field associated with the drilling rig” (Texas, 1986). This description is ambiguous in describing whether water used for HF is considered part of the drilling and exploration stage of fossil fuel production or part of the completion stage, leaving GCDs with the interpreting authority. In 2013, the Texas Association of Groundwater Districts conducted an informal survey of GCDs located in oil and gas producing areas, showing 38% of districts required permits for frack supply wells (Lashmet, 2015). This low proportion may be attributed to the historical “hands off” approach regarding provisions made to broadly apply to oil and gas activities. However, considering recent record-breaking drought and increasing water use for fracking, GCDs are beginning to adopt more assertive policies imposing frack supply wells are not exempt from these oversights (Lashmet, 2015).

Encompassing one of the largest and more productive areas of the EF, Evergreen GCD requires oil and gas operators seeking to drill a frack supply well to obtain permits, and to comply with a yearly production limitation of 652,000 gallons per acre (Lashmet, 2015). To monitor this provision, Evergreen GCD requires well owners to provide monthly pumping reports (Lashmet, 2015). Reporting district water usage greatly assists in the GCD's responsibility in estimating the amount of groundwater pumped on an annual basis, feeding into regional evaluations of modeled available groundwater.

In contrast to Evergreen GCD, Wintergarden GCD interprets frack supply wells as exempt under Texas Water Code Chapter 36.117b and does not require a permit for drilling a frack supply well (Lashmet, 2015). This means there are no production limits, well spacing requirements, or reporting requirements imposed on these wells, creating some difficulty for the GCD in its reporting of yearly water usage. This lax regulation on frack supply use means the GCD must rely on outside sources to estimate water use trends or rely on the voluntary reporting of a few to estimate total use over the whole district. These provisions also leave room for potential groundwater conflicts between neighboring entities that are pumping from the same aquifer. It is important to note that although well permitting is not required in Wintergarden GCD, all exempt wells still must register with the district and adhere to the minimum well design and completion standards stated in GCD by-laws. By this provision, the GCD is still informed on the number of frack supply wells in the district. This can aid in determining water use estimates.

McMullen GCD, Live Oak Underground Water Conservation District (UWCD), and Pecan Valley GCD all govern rig and frack supply wells by a mixed approach of the former GCDs (Lashmet, 2015). Although both districts view frack supply wells as exempt from pre-drilling permits, they are still required to register the well and report water production to the district (Lashmet, 2015). By this approach, oil and gas operators are still allowed free reign over water production, but the district can accurately incorporate fracking water use into their management planning and modeling of available groundwater. In addition to reporting the total monthly water withdrawals for oil and gas activities, Pecan Valley GCD requires reporting of the quantity of water necessary for such activities and the quantity of water withdrawn for other oil and gas purposes. This provision allows for more detailed water use reports on both drilling activities and HF water use from oil and gas operators.

The last district discussed here in detail is an interesting case in the effort to balance groundwater rights while acknowledging competition between users. Gonzales County UWCD, located in the northeastern portion of the EF, is one of the few districts that explicitly separates the distinction of rig supply and frack supply wells in the district by-laws. Although both well types are still considered exempt and do not require water use reporting, the district only outlines specific requirements for frack supply wells. Regardless of which aquifer is pumped, the water quality must exceed 3,000 parts per million TDS, or if in a shallow, undefined aquifer formation, must be screened at a minimum depth of less than 105 m. This provision does not place any regulation on deeper, undefined aquifers, encouraging oil and gas operators to use these groundwater sources as a means to avoid closer GCD oversight.

In summary, the heterogeneity of regulations placed on EF energy producers result in a complex network of management structures that can directly affect groundwater use for HF. By understanding the specific incentives in place, or lack thereof, drawdown effects may potentially reveal areas where management more efficiently addresses groundwater competition. The EF region varies greatly at a local scale in population density, economy, and natural resources. Therefore, it is expected that a local GCD is well practiced in implementing regulations that are pertinent and beneficial to the groundwater users it represents. All things considered, provisions made in one GCD have the capacity to be viewed as a standard to other GCDs, with the potential to improve planning and management across a region.

3. METHODS

3.1 Preliminary FracFocus Database Preparation to model HF water use

The FracFocus Chemical Disclosure Registry is a commonly used database for oil and gas operators for reporting the chemicals used during a HF process (Council, 2013). Aside from the chemicals used, an entry into this database includes information surrounding: 1) Job Start Date; 2) Job End Date; 3) Well Name and Number; 4) Latitude; 5) Longitude; 6) True Vertical Depth; 7) Total Base Water Volume (gallons); and 8) Total Base Non-Water Volume. In Texas, reporting to FracFocus became legally required in February of 2012, whereas all reporting prior was only voluntary.

For the purposes of this study, well entries in the EF region reported from April 2011 to September 2018 were used to evaluate trends in EF HF water use. FracFocus database covers the entire state of Texas, so well entries outside the extent of the EF region were filtered out. Priority attributes in each data entry include: 1) Job Start Date; 2) Job End Date; 3) Latitude; 4) Longitude; and 5) Total Base Water Volume (gallons). Given both the start and end date of a HF event, the total water volume may be calculated over the days of active HF to produce an average pumping rate. This approach enabled the evaluation of water use trends for HF over time, and identifying areas of intense HF water use.

3.1.1 Quality assurance using Interquartile Range Method

For quality control purposes, the interquartile range (IQR) method was executed on the acquired FracFocus data, following the approach used by Hernandez-Espriu et al. (2018). This was performed to handle missing values and distinguish between mild and extreme outliers, in which unacceptable values were omitted from the dataset. The IQR method is a simple and robust measure of variability, since only the central 50% of data distribution is factored into the computation of IQR (Barbato, 2011). The IQR is calculated from the lower limit 25th percentile of values (Q_1), the median (Q_2), and the upper limit 75th percentile (Q_3), where values within this range are considered accepted values (Equation 1, 2, 3). In the context of FracFocus database, outliers may represent mistakes since the data was entered by hand. Examples of this within the dataset include abnormally small water volumes reported as the total water used in a HF event, and other cases reporting 99 million gallons.

$$IQR = Q_3 - Q_1 \tag{1}$$

$$Lower\ limit = Q_1 - 1.5IQR \tag{2}$$

$$Upper\ limit = Q_3 + 1.5IQR \tag{3}$$

3.2 ArcGIS Spatial Analyses

Current regulations do not require reporting the source location of the water used in a HF event. Therefore, the water reportedly used for HF in the

FracFocus database was spatially correlated using ArcGIS to the location of water wells in the Submitted Drillers Reports (SDR) Database to estimate groundwater sourcing (Texas, 2015). The SDR database is accessible through the TWDB. It includes information regarding the proposed well use, location, and borehole depth. One shortcoming in this approach is that the SDR database lacks other useful attributes, such as well screening depth and target aquifer. This information is only accessible online by searching through PDF reports filled out by well drillers, in which filling in these attributes would be very time consuming and still have much missing data like target aquifer the wells were screened in. Instead, this can be estimated quickly using GIS data supplied by the TWDB GAMs. The following sections outline how these three data sources were utilized to determine the aquifer that these wells were screened in and assign pumping rates to rig/frack supply wells.

3.2.1 Determining aquifer and properties of rig/frack supply wells

When a well is entered into the SDR database, its intended use prior to drilling is recorded. All wells classified as either rig supply or frack supply were downloaded from the SDR database. The inclusion of both well types was due to the ambiguous nature of classifying well uses and accounts for changing intended well use after the drilling and reporting to the SDR database has occurred. Therefore, in this analysis, both rig and frack supply wells were assumed to supply water for HF during its operating lifetime.

Upon request made to the GAM section at the TWDB, GIS data made in conjunction with the GAMs allowed for efficient assignment of aquifers to rig/frack supply wells. The elevations of the upper and lower surface of aquifer formations were supplied for the major Carrizo-Wilcox and Gulf Coast Aquifers, and the overlying minor aquifers. The Carrizo-Wilcox aquifer GAM is divided into three models, one for the southern, central, and northern regions of Texas. Aquifer data was taken from the Southern portion of the Carrizo-Wilcox Aquifer GAM, supplying aquifer formation top and bottom elevations, listed in order of increasing depth: 1) Queen City; 2) Recklaw; 3) Carrizo; 4) Calvert Bluff (Upper Wilcox); 5) Simsboro (Middle Wilcox); and 6) Hooper (Lower Wilcox). Aquifer layers in the Carrizo-Wilcox GAM are best visualized in Figure 3-1. Similarly, using the Central portion of the Gulf Coast Aquifer System GAM, the following formation top and bottom elevations are supplied, listed in order of increasing depth: 1) Chicot; 2) Evangeline; 3) Burkeville confining unit; and 4) Jasper. The following steps describe how each supply well was assigned to an aquifer. This was performed separately for wells within the spatial extent of the southern portion of the Carrizo-Wilcox Aquifer GAM and the central portion of the Gulf Coast Aquifer GAM. Results from this analysis estimated the primary major aquifer used to supply groundwater for HF, in which only those wells were utilized in the succeeding analyses. Therefore, aquifer drawdown modeling was constrained to a single aquifer system. Although aquifer formations may be isolated from one another within a system, analysis was performed in an effort to include the greatest count of HF events while still summarizing comprehensive impacts on a major aquifer system.

Within the Overlay toolset of ArcGIS, Intersect analysis was used to estimate a supply well's target pumping aquifer (ArcGIS Pro, 2018). The Intersect tool computes a geometric intersection between input features that overlap in all layers and/or feature classes. To assure data type compatibility, the aquifer top and bottom elevation layers, originally supplied in single-band raster format, must be converted to a vector data type to be processed with the supply well point data. This is done using the Raster to Polygon tool located within the Conversion toolset. After converting every elevation layer, each must be overlaid in geologic order. This is a crucial step before executing the Intersect tool.

To execute the Intersect tool, the supply well point feature class and elevation layers are entered as Input Features. The elevation layers are listed in geologic order so that the youngest formation is towards the top of the list, with the rig/frack supply well feature class entered above all aquifer layers. The 'JOIN ALL ATTRIBUTES' option should be selected and the output type should be specified as 'POINT.' Running the tool with the proper setup will result in the formation depth of each layer now embedded in the supply well feature class attribute table.

Now that the supply well feature class contains the formation depths at each well location, its depth can be used to estimate the deepest formation it has been drilled into. Using the 'If-Then' function in Excel, the wellbore depth was used to reference the depth of each layer in which a label was assigned depending on if the depth fell within the top and bottom elevation of a formation. A 10m buffer was included within the function as an added precaution to assign wells that are fully penetrating a formation.

Some wells did not appear to be screened in any of the major or minor aquifers. There were two categories of these. Wells with depths that did not penetrate as deep as the upper surface of the shallowest aquifer formation were labeled as ‘Shallow’. Wells with depths that exceeded the deepest formation elevation or were completely outside the boundaries of any GAM were labeled ‘Deep’. Despite being outside GAM boundaries, these wells are still presumed to have access to groundwater.

After aquifer assignment was completed on all frack supply wells, additional geospatial data regarding aquifer parameters was utilized to determine the transmissivity (T) and storativity (S) at each well site. Aquifer parameter values were only available for the Gulf Coast aquifer. Well parameters in the Carrizo-Wilcox were assigned using results from Mace et al. (1999). This was performed to create a HF water supply database to use for aquifer drawdown modeling.

The results from this section will feed into a later method of establishing a water supply network for hydraulic fracturing and will thereafter serve as inputs for aquifer drawdown modeling.

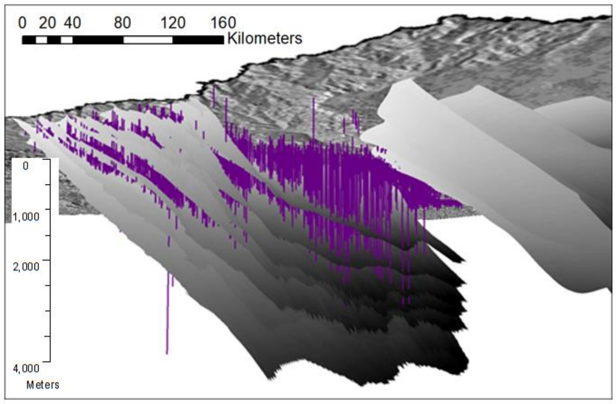


Fig 3-1: 3-Dimensional conceptualization of aquifer layers being intersected by rig/frack supply wells (purple), with a 20x vertical exaggeration. View is from below the surface facing northeast through the southeastern dipping aquifer formations.

3.2.2 Measuring spatial distribution of HF demand/supply

As discussed in Section 2.6.1.2, groundwater supply for HF is considered a relatively local resource, commonly transported by trucks and pipelines or produced on site. A key step before estimating the location of groundwater withdrawal for HF was to solidify this notion of local groundwater use and to determine the appropriate next step of establishing a water supply network. This was performed using the Near analysis tool from the Proximity toolset in ArcGIS to measure the spatial distribution of rig/frack supply wells to HF locations (i.e. FracFocus data points).

The Near analysis tool processes two input features to calculate distance and other proximity information between the closest feature with other layers or feature classes. The Near analysis tool was executed by entering the FracFocus data as the input features and the rig/frack supply wells as the near features. No search radius was specified to ensure all features were considered in the analysis.

Additionally, the ‘GEODESIC’ method of distance calculation was selected to account for the curvature of the specified geographic coordinate system (North America Equidistant Conic). After running the tool, near distances were embedded into the attribute table, calculating the nearest distance between FracFocus data points to rig/frack supply well points.

Results from Near analysis do not explicitly account for the distance traveled by trucks following a road system. A more in which a more appropriate method for this would be the Manhattan Distance method. Considering the lack of available road network data at the needed resolution, however, the use of Near analysis was chosen.

3.2.3 Establishing a water supply network for HF

The assumption of local groundwater use in HF water supply was delineated geographically through a Thiessen Polygons network analysis. A similar approach was used by Brumbelow and Georgakakos (2007) to estimate local water consumption by crops in small scale subsistence farming. The objective of a Thiessen Polygon network was to define polygon areas around a set of points to define any attribute within an area as corresponding to that point (Figure 3-2).

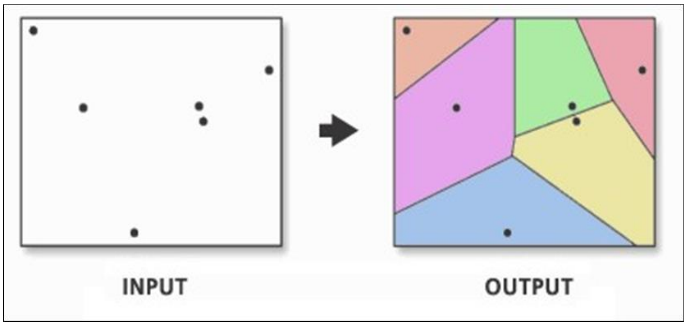


Figure 3-2: Conceptual input and output results from a theissen polygon network analysis. (Source: pro.arcgis.com/en/pro-app/tool-reference/analysis/create-thiessen-polygons.htm)

A Thiessen Polygon network spanning the entire EF region was created. Overlying the network with the HF wells it is apparent that the polygons are smaller in dense areas of HF events. After intersecting the Theissen Polygon network with HF wells, the final result is a schedule of HF events. occurring within a local area that are spatially correlated to a rig/frack supply well. However, it is important to recognize this is simply an estimate of groundwater sourcing.

3.2.4 Identifying at-risk wells by sector

In the town of Barnhart, Texas, intensified groundwater use for HF resulted in an increase in competition and loss of available water for the city, ranchers, and farmers. This eventually led to the demise of economic activity and social contentment (see Section 2.6.3.2). Although Barnhart is an extreme example, identifying the sectors most vulnerable to these potential impacts is a crucial step toward mitigating and managing groundwater competition. To predict the groundwater users potentially impacted by aquifer drawdown and competition in the EF, the spatial distribution of wells from the municipal, industrial, livestock, irrigation, and domestic sectors were compared with the rig/frack supply wells in the region. Knowledge of the spatial distribution between these wells is pertinent to predicting which sectors have elevated risks of experiencing negative groundwater impacts from local HF. Keeping in mind the assumption that HF demands local groundwater, aquifer drawdown from rig/frack supply well pumping has the potential to influence groundwater availability and well functionality to other sectors within a local radius.

To identify wells at-risk of experiencing aquifer drawdown impacts from HF, a Near analysis was performed on rig/frack supply wells in reference to all municipal, industrial, livestock, irrigation, and domestic wells (ArcGIS Pro, 2018). To execute the Near Analysis, rig/frack supply wells were regarded as the input features into the tool, in which each well sector type was input as a separate feature layer and regarded as the near features. This application is appropriate because aquifer drawdown, in theory, occurs in a predictable radius based on local aquifer characteristics, withdrawal volumes, and pumping time.

3.3 Aquifer Drawdown Modeling

In Texas, GAMs are common tools used to evaluate groundwater availability and water levels in response to potential droughts and future pumping. These models are part of the long-term groundwater planning process and are commonly used to estimate the impacts of pumping on aquifer water levels 50 years into the future. These models provide an integrated tool for the assessment of water management strategies on a regional scale, however, are not directly applicable for predicting conditions at individual well sites. The scale of this thesis requires a resolution not met by both the Carrizo-Wilcox Aquifer GAM and Gulf Coast Aquifer GAM, which function under 1-mile grids. Therefore, a modeling method that calculated simple drawdown at the individual well scale was deemed more appropriate to assess short term pumping impacts.

The ability to model aquifer drawdown from publicly available input parameters offers a unique opportunity to educate professionals outside the field of hydrogeology on the impacts of groundwater pumping on neighboring wells, otherwise known as competition. By utilizing basic hydrogeologic principles in a transparent method, this study aims to increase synergy between the Water-Energy-Food (WEF) nexus of professionals working to enhance efficiency within all domains. While water need/demand is a rigorously studied subject in the realm of WEF research, the limitations of, and the impacts on, natural resources are not always accounted for, especially when that resource is hidden in complex geological formations underground. With this modeling approach we hope to bridge the groundwater knowledge gap and give professionals from all backgrounds a method for assessing groundwater competition in the WEF environment.

3.3.1 Aquifer drawdown modeling using the Theis Solution (1935)

The Theis (1935) solution is a well-known analytical method used in determining the transmissivity and storativity of confined aquifers from pumping and recovery tests. When both of these aquifer parameters are known, however, the Theis (1935) solution can be used to forward model the radial distance and depth of aquifer drawdown in response to pumping. Drawdown of an aquifer (s) at a given distance, r, from the pumping well at time, t, is related to the well function (W(u)). Incorporating the well function argument, u, to calculate W(u), aquifer drawdown (s) is modeled over time and space (Equation 4, 5, 6). A standard type curve relates the theoretical response of an aquifer to pumping and is obtained by plotting W(u) vs. 1/u, where:

$$u = \frac{r^2 S}{4Tt} \tag{4}$$

$$W(u) = -0.5722 - \ln(u) + u - \frac{u^2}{2*2!} + \frac{u^3}{3*3!} - \frac{u^4}{4*4!} + \cdots \tag{5}$$

$$s = \frac{Q}{4\pi T} W(u) \tag{6}$$

The assumptions of the Theis solution are listed as: 1) the aquifer is infinite in extent, with no constant head boundaries, no-flow boundaries, or any other heterogeneity, 2) the aquifer is homogenous, with a constant transmissivity and storativity over its infinite extent, 3) the pumping well does not induce additional leakage or recharge to the aquifer, 4) the pumping well fully penetrates the aquifer, and 5) groundwater flow is horizontal, adequately described by Darcy (1856). Acknowledging the assumptions with this method are important in understanding its limitations when compared to a more complex, numerical model.

This application of the Theis (1935) solution is done in a similar manner to Brozović's (2010) study in assessing the economic impacts of groundwater management while incorporating spatial dynamic flow equations. The study describes current economic analyses of groundwater management as subpar, using single-cell aquifer models that assume instant and uniform responses to groundwater pumping. Brozović's (2010) spatially variable method in groundwater assessment revealed economic impact to be several orders of magnitude larger than predictions using single-cell models, concluding that a spatial and temporally explicit model would predict much larger economic gain in response to optimal management. As this study plans to evaluate the economic impacts of modeled drawdown from HF, these findings further support the need to apply such methods to the EF.

3.3.2 Aquifer drawdown modeling approaches

3.3.2.1 Annualized aquifer drawdown

Annualized Theis drawdown was computed in ArcGIS using a python-based geoprocessing tool by Inkenbrandt (2016) to compute Theis drawdown at the GCD scale. During the permitting process of a new well, desired pump rates are annualized to aid in managing aquifer drawdown and well spacing. The utility of modeling annualized pumping rates is that the spatial extent of aquifer drawdown surrounding the well is much greater than if pumping was modeled over just a few days. Both the magnitude of drawdown and the spatial extent of that drawdown resulting from an intended permit are at the discretion of the GCD manager to determine what are the appropriate levels. Considering most water use across sectors is a fairly constant demand through time, annualizing the pumping rates for all wells in a district is an efficient method to generalize drawdown at the district scale, assuming that all wells are pumping at their permitted limits. This method was used in this thesis for rig/frack supply wells only, using volumes reported by FracFocus to determine the land types affected by drawdown for every year in each GCD. Although GCD managers possess copious knowledge of their district and its priorities, these models can build a summary of each GCD to better inform management/policy decisions that are being made remotely. This method will also test the success of individual management policies between districts that can then be compared to the results from the transient drawdown modeling approach outlined above.

To execute the geoprocessing tool, the resultant rig/frack supply wells from the Theissen polygon analysis were partitioned by year for each GCD. Each HF event was designated an annual pumping rate based on its total reported volume. Annualized events were input into the tool, along with transmissivity, storativity, raster cell size, and a buffer distance. To produce a conservative estimate of the spatial extent of drawdown, geostatistical analysis on coincident HF events was adjusted to compute the average of drawdown within an area. In the case that groundwater pumping did not occur within a GCD in a given year, this year was excluded the results.

3.3.2.2 Transient aquifer drawdown

MATLAB was used as the primary framework for organizing spatial analysis results and computing transient aquifer drawdown between the years 2011 and 2018 (Code A-1). Results from the Thiessen polygon network analysis produced a table of 10,364 HF events that were assigned to a rig/frack supply well with its associated aquifer, transmissivity, and storativity parameter. Each HF event records a total water volume pumped with a start and end date. These attributes were used to calculate a pumping rate that spans the length of each event. The HF events were partitioned among 1,419 rig/frack supply wells. In the case that multiple HF events occur at the same time within the same Thiessen Polygon of one rig/frack supply well, pumping rates at the specified well.

Transient drawdown modeling was constructed to efficiently process thousands of pump events over hundreds of rig/frack supply wells at a time resolution of one day (Code A-2). This was accomplished through mapping drawdown during instances of pumping on local grids that were set to model up to a 1,000 m radial distance from each pump event. Theis drawdown was then calculated among simulation points spaced by 200 m within each local grid. This method offered more localized detail than some regional models built on 1.6 km (1 mile) grids. Both drawdown and recovery were modeled using the Theis function, making the assumption that recovery time was equal to the number of pump event days.

3.4 Groundwater Competition Analysis

3.4.1 Land impact analysis from annual drawdown

Although results from the annualized drawdown method do not define time-dependent competition among inter-sector wells at the daily time scale of an industrial process like fracking, it can be used to determine the land use types that fall within the threshold of modeled drawdown. A key goal from this analysis was to identify the land types impacted by drawdown and quantify the severity of drawdown in each area. Depending on the types of land impacted, this analysis estimated potential stakeholders impacted by drawdown from HF. This may also inform stakeholders in the case that they are seeking to develop a groundwater well on land in the future. Land impact analysis was performed for each GCD, where the annual drawdown for each year is averaged to maintain a conservative estimate over the 2011-2018 production timeframe. Results from this analysis will determine the potential stakeholders affected by drawdown and the severity. The quantity of drawdown coverage over the varying land types will offer a summary of the economic sectors under highest competition with groundwater pumping for HF.

Land use analysis was conducted using the latest (2011) land cover dataset from the National Land Cover Database (NLCD) (Homer, 2012). Yearly drawdown predictions were averaged using the Raster Calculator spatial analyst tool and combined with the land use raster using the Combine spatial analyst tool in GIS. After these steps, raster pixel size and count for each land use category was segregated by average drawdown in increments of 1 m. Pixel size and count is transformed into km^2 using the NAD 1983 Contiguous USA Albers projection.

The case of Barnhart city revealed that public supply, livestock, and irrigation wells all experienced limited groundwater availability as a result from newly developed groundwater pumping operations for hydraulic fracturing. Thus, land use types designated as ‘Developed’, ‘Pasture/Hay’, and ‘Cultivated Crops’ were determined to be priority areas to be examined during the modeling of drawdown. Land development can range from low to high intensity, providing for more domestic dwellings and public supply utilities. However, public supply wells may not be located within the city limits to which they are serving. ‘Pasture/Hay’, while not irrigation intensive, serves livestock with food and roaming land. Other lands such as ‘Barren/Shrubland’ and ‘Grassland’ are expected to serve as other roaming areas for livestock and will be examined. Lastly, ‘Cultivated Crop’ land is a high priority land type that will be examined for drawdown impacts because of its intensive water use. Whereas a well impact analysis was performed using the transient model, a land impact analysis determined the extent of economic stakeholders impacted by oil and gas groundwater use to supply for HF.

3.4.2 Well impact analysis from transient drawdown

3.4.2.1 Annualized, regionally averaged drawdown approach

To show the advantage of the transient drawdown modeling approach for estimating impacts on wells from other sectors, wells in the EF were intersected with the average annual drawdown raster that was created from each year of annualized pumping. The 95th and 50th percentile ranges of drawdown were then used to determine the additional pumping costs for each sector well, where impacted sectors included agricultural wells, domestic wells, industrial wells, livestock wells, and public supply wells. Whereas the transient model assessed impacts across 8 years of high resolution, high frequency pumping, the annualized drawdown model was expected to be a rough estimation of the study period. Considering the ephemeral nature of pumping for HF, in both its water intensity and spatial distribution, it is unclear how results from annualized pumping rates will compare to the transient method.

3.4.2.2 Transient Drawdown Modeling Approach

The implementation of a transient drawdown technique is more applicable to address public reports of limited groundwater production from wells once a nearby HF supply well starts pumping. The impacts of pumping on well water levels is highly time-dependent because a HF treatment commonly spans a length of days to weeks. After this the well may then be inactive for months. These short-term drawdown affects were modeled at a daily resolution. Drawdown from these rig/frack supply wells intermittently intersect with surrounding wells of other sectors. Both the length of time each well from another sector experiences additional drawdown and the magnitude of that drawdown results in an expected cost associated with pumping. This additional cost for pumping from deeper water levels in wells can be compared to the annual Gross Domestic Product (GDP) of the household or entity that pays for the operation of that well. If modeled drawdown is large enough in an intersecting well, the pump may burn out or need to be lowered, or in some cases the well may be deepened. These costs are not included in the analysis in this thesis since the depth of the pumps is not easily accessible for thousands of wells in the SDR database. Therefore, the estimated costs to other sectors from pumping for HF likely under-estimates the true cost.

3.4.2.2.1 Economic Impact on Wells from Transient Drawdown

Cost impacts were calculated for all wells taking into account specific socio-economic factors based on the well sector impacted and the GCD it is located within. A formula for calculating the cost of pumping groundwater from a specified depth is applied to quantify the additional cost from the additional drawdown from pumping for HF (Equation 7). Pumping cost (C) (USD/hour), is a function of volumetric pump rate (*Q*) (US gpm), depth to water level (*h)* (ft), electricity cost rate (*c*) (USD/kWhr), and pump and motor efficiency constants (μ_p, μ_m) (Engineering Toolbox, 2016).

$$C = \frac{0.746Qhc}{3960\mu_p\mu_m} \tag{7}$$

In this equation, *h* represents the depth to water level. For this thesis, however, *h* is treated as the additional distance (Δh) to the potentiometric surface in response to pumping for HF.

Electricity cost rates for Texas cities are classified into three categories: 1) Commercial; 2) Residential; and 3) Industrial use (Texas, 2019). Sector wells were subdivided into these three types using distinctions made by the U.S. Environmental Protection Agency (EPA). Public supply wells fall under commercial electricity use, domestic wells fall into residential, and agricultural, livestock, and industrial wells fall into industrial electricity consumption. Electricity rates from cities within each GCD were averaged to estimate general costs throughout the district, though fairly constant over space. The electricity rates utilized for cost impact calculations for each GCD are summarized in Table 3-1. In addition to Δh and c input variables, the daily pumping rate for each GCD sector well was estimated from historical groundwater use surveys published by the TWDB (2002). Total groundwater production by sector was average over the number of type wells within the district (Table A-1).

Table 3-1: Electricity rates (cents/kilowatt hour) by user type averaged for each GCD.

Groundwater Conservation District (GCD)	Electricity Rate by Classification (¢/kWh)		
	Commercial	Industrial	Residential
Evergreen	8.16	5.57	10.98
Gonzales	8.58	6.48	11.09
Live Oak	8.16	5.57	10.98
McMullen	8.16	5.57	10.98
Pecan Valley	8.16	5.57	10.98
Wintergarden	8.16	5.57	10.98

Well pump and motor efficiencies were held constant in all cost impact calculations since motor sizes were unknown. A study conducted by Evans (1991) evaluating the pumping costs for agriculture wells included an assessment of pump and motor efficiencies based on a well's electric motor capacity, in kW. Motor capacities ranged from 2 to 55 kW, resulting in pump efficiencies between 55 to 85% for both submersible and turbine pumps and motor efficiencies between 80 to 93%. Transferring these results to overall pump efficiency, Evans (1991) determined a well's typical overall efficiency to be between 44 and 79%. The average between both pump and motor efficiencies found in this study were used as inputs into the cost impact formula, setting $\mu_p = 0.70$ and $\mu_m = 0.865$.

4. RESULTS

4.1 FracFocus Hydraulic Fracturing Volume Trends in the Eagle Ford

Evaluation of HF water volumes for the Eagle Ford between the years 2011 to 2018 reveal a steadily increasing trend in water volume per HF treatment (Figure 4-1). In 2011, the average HF treatment volume was 15,000 m^3. In 2018, that volume had increased to over 41,000 m^3. To explore the impact of year-to-year fluctuations in oil and gas prices, HF water volume entries were divided into two periods. During the 2011 to 2014 timeframe, the Energy Information Administration (EIA) reported a rig count of 240 for the whole EF region. During this time period the price of a barrel of oil was 100 US dollars (USD) (EIA, 2019). In the years following the fall of oil prices in 2014, however, rig counts had dropped to below 50 during the period of least activity during 2016, when prices were less than 50 USD/bbl (Figure 4-2).

During the first few years of energy development in the EF, a HF treatment was commonly 15,000 m^3, whereas after the collapse in energy prices in 2014 treatment volumes of 27,000 m^3 became more common. This increase in water demand per HF treatment was accompanied by a 44% decrease in HF events, as compared to 2013. These results support industry claims of water use per HF treatment increasing with technological advancements (i.e. increased well length and proppant volumes). Although the number of HF events decreased in recent years, water demand intensified and became more spatially concentrated.

This intensification of water demand by HF will impact the severity of localized drawdown in water levels in neighboring wells.

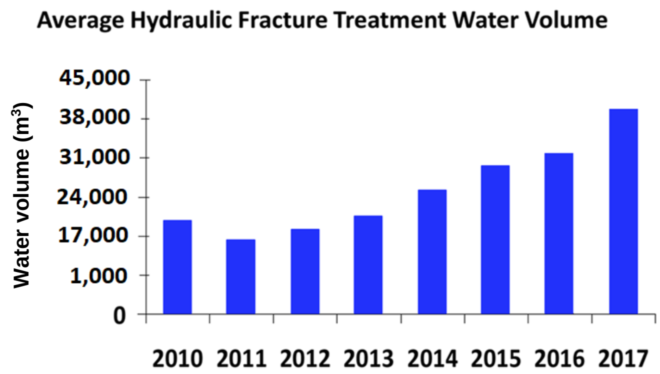


Fig 4-1: Average annual volume of water injected per HF treatment in the Eagle Ford.

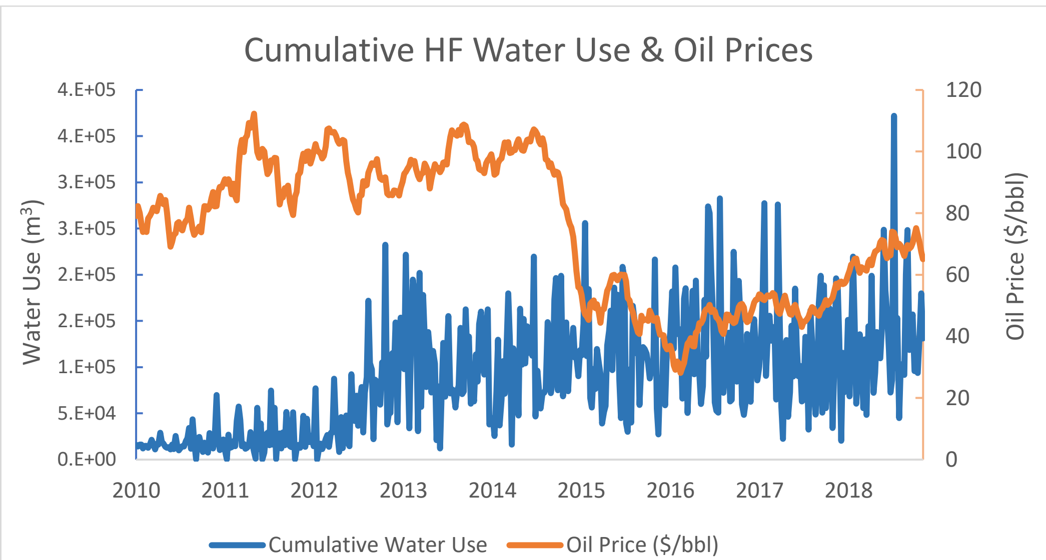


Fig 4-2: Total monthly water consumed by hydraulic fracturing in the Eagle Ford in relation to national oil prices.

4.2 Findings from Spatial Analysis

4.2.1 Designating Aquifers for Wells and Assigning Aquifer Properties

Designating aquifers (summarized in Figure 4-3) for the 1,419 rig/frack supply wells revealed that 510 wells were drilled to depths that were deeper or outside the aquifer layer boundaries in the GAMs. These deeper wells were aggregated in the northeastern region of the Eagle Ford and in discrete zones in the western region. In contrast, 154 wells were classified as ‘Shallow’ and also clustered with the deeper wells in the northeastern region. Forty-two wells were classified as targeting the Queen City aquifer, making up a layer in the Carrizo-Wilcox aquifer GAM. Wells assigned to the Queen City aquifer were concentrated in the southernmost portion of the Eagle Ford and in a small area in the northeast. Below the Queen City, only 13 wells were assigned to the Recklaw formation, which has been characterized as a confining unit. Eight of these wells fall within the central region of the Eagle Ford. Eighteen wells were assigned to the Carrizo Sand formation with a slight tendency to be located within the central portion of the region.

In the Wilcox Group, 170 wells were assigned to the Calvert Bluff formation and were located predominantly in the western half of the region. Three hundred and fifty-six wells were assigned to the Simsboro aquifer and these are located throughout the western half of the EF region. Although wells were assigned to the Simsboro in the eastern half, their occurrence is infrequent and only concentrated along the northernmost part of the region. Seventy-seven wells were assigned to the Hooper aquifer. This is the deepest modeled aquifer within the Wilcox Group. Wells assigned to the Hooper aquifer were concentrated within the westernmost region of the Eagle Ford. Within the Gulf Coast aquifer system, 14 wells were assigned to the Chico aquifer, 8 to the Evangeline aquifer, 40 to the Burkeville confining unit, and 16 to the Jasper aquifer. These wells are concentrated in the easternmost portion of the Eagle Ford, occurring predominantly in bands along the southern boundary. Results from estimating aquifer sources for rig/frack supply wells are mapped in Figure 4-4.

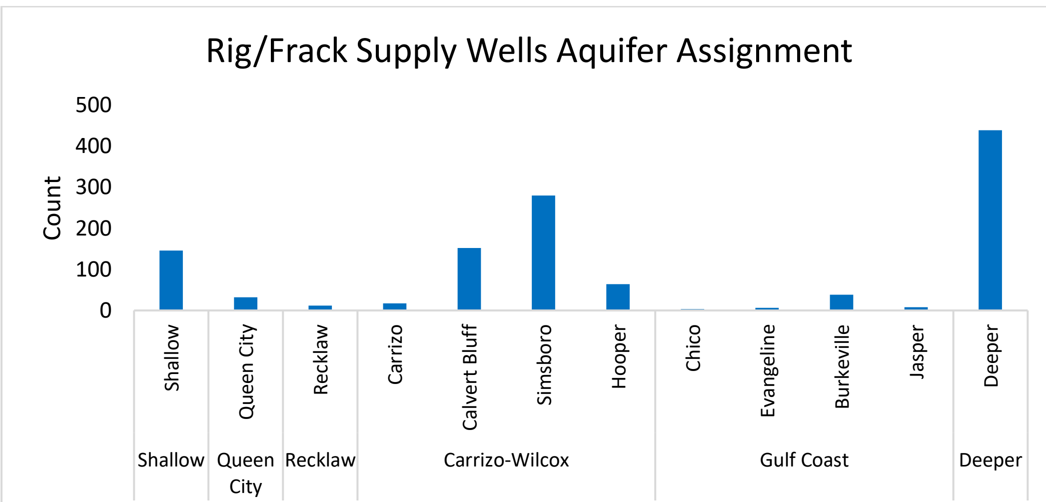


Fig 4-3: Estimated count of wells used to supply water for HF categorized by targeted aquifer formation.

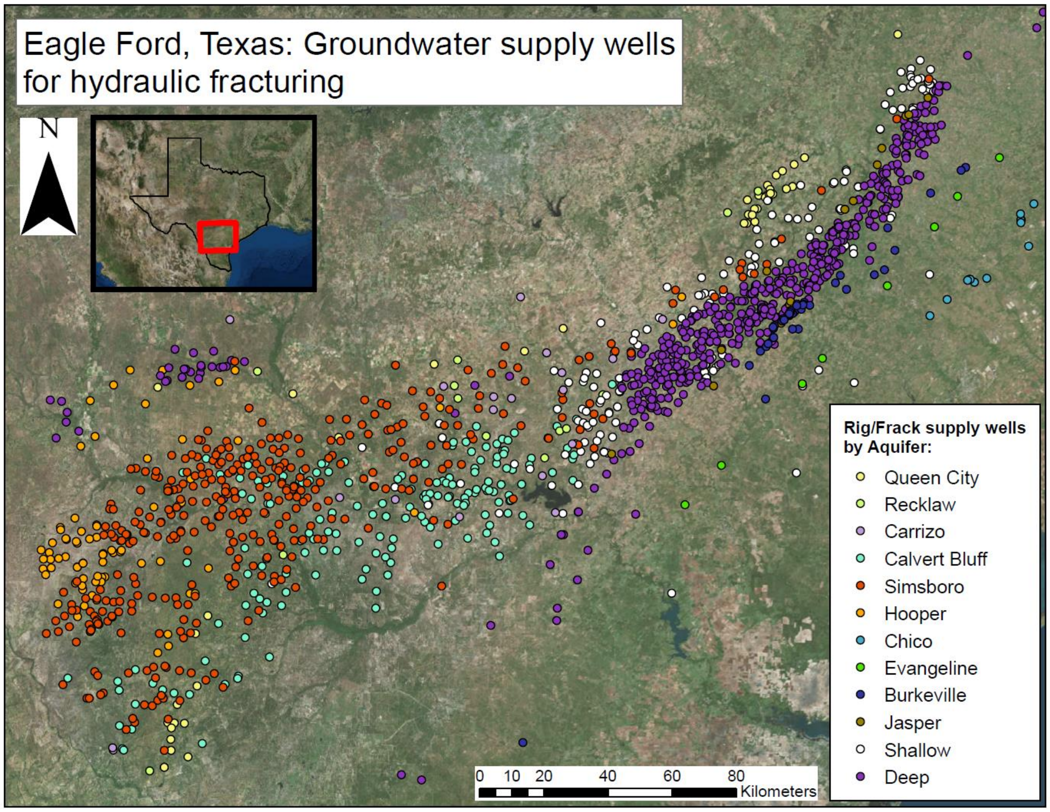


Fig 4-4: Estimated aquifer formation supplying rig/frack supply wells in the Eagle Ford.

Looking closer at rig/frack supply well aquifer designations by GCD, Wintergarden GCD, Evergreen UWCD, and Pecan Valley GCD had the highest portion of rig/frack supply wells in the region, with 355, 349, and 228 wells, respectively. These are followed by McMullen GCD, Gonzales UWCD, and Live Oak UWCD, with 101, 60, and 57 wells, respectively. Although the number of rig/frack supply wells give insight into the extent of HF activity within a district, it is important to keep in mind that well owners from other sectors have reportedly sold groundwater to HF operations. This pathway for attaining groundwater avoids drilling a well and can reorganize the spatial distribution of pumping. To explain further, the spatial reorganization of pumping is owed to the fact that the volume of a HF treatment is still recorded, whether or not the groundwater is sourced from an official rig/frack supply well or from a local's well. This means if the water was indeed sourced from an unofficial well, its location of modeled drawdown was shifted to the nearest rig/frack supply well instead. Therefore, since HF volumes are reported, the pumping location to supply water for each HF treatment is distributed in this analysis to the nearest officially designated rig/frack supply wells using the Thiessen Polygon method.

Wells assumed to be screened from deeper formations than what was modeled in the TWDB GAMS account for a large portion of total wells in Pecan Valley and Evergreen GCDs. They account for approximately 78% (177/228) and 53% (300/349), respectively. The absence of shallower well assignments in the western half of the region may be attributed to its semi-arid climate, resulting in higher use of deeper, more reliable groundwater. Following this trend, approximately 56% (198/355) of wells in Wintergarden GCD were assigned to the Simsboro aquifer, 20% (68/355) were assigned to the Calvert Bluff, and 16% (58/355) were assigned to the Hooper. Thus, groundwater supply for HF in Wintergarden GCD was almost entirely from the Wilcox Group aquifer system (325/355). Among these aquifer formations in Wintergarden GCD, there is a deepening trend in wells from the south, moving northwest to areas with more agriculture activities. The remaining aquifer assignments are summarized in Table 4-1.

Table 4-1: Count of estimated aquifer assignments for rig/frack supply wells categorized by GCD.

Count of Aquifer Well Assignments													
	Shallow	Queen City	Recklaw	Chico	Evangeline	Carrizo	Calvert Bluff	Simsboro	Hooper	Burkeville	Jasper	Deeper	Grand Total
PECAN VALLEY GCD	8	-	-	3	1	-	-	-	-	35	4	177	228
EVERGREEN UWCD	57	4	8	-	-	11	6	54	5	2	2	200	349
WINTERGARDEN GCD	3	4	1	-	-	1	68	198	58	-	-	22	355
GONZALES UWCD	27	23	2	-	-	-	-	4	-	-	1	3	60
MCMULLEN GCD	7	-	-	-	-	3	71	18	1	-	-	1	101
LIVE OAK UWCD	22	-	1	-	-	2	7	5	-	-	1	19	57
Total	124	31	12	3	1	17	152	279	64	37	8	422	1150

Results from this analysis revealed the Carrizo-Wilcox aquifer system was the most common major aquifer assigned to rig/frack supply wells. To constrain modeled drawdown in the major groundwater source used to supply HF demands, only groundwater wells in the Carrizo-Wilcox aquifer system were modeled for drawdown and well sector impacts. Despite over 45% of wells assigned as 'Shallow' throughout the region, aquifer properties were unable to be determined because there are no official groundwater sources mapped by the TWDB for this group. The next greatest count of rig/frack supply wells were in the Carrizo-Wilcox aquifer system, making up approximately 35% of the rig/frack supply wells in the region. Average rig/frack supply well depths for each aquifer formation within the Carrizo-Wilcox aquifer system are summarized as: 1) 880 m for wells assigned to the Carrizo Sand formation; 2) 3,700 m for wells assigned to the Calvert Bluff formation; 3) 800 m for wells assigned to the Simsboro formation; and 4) 550 m for wells assigned to the Hooper formation. The average borehole depth of wells that were designated ‘Deeper’ was found to be approximately 800 m. Although deeper or outside TWDB GAM model boundaries, ‘deeper’ wells were included in the drawdown analysis with the Carrizo-Wilcox wells in an effort to maintain a more comprehensive drawdown and cost impact to surrounding wells. Additionally, although GIS aquifer layer data only mapped the extents of the aquifers within suitable drinking water standards, the stratigraphy of these layers can be assumed to continue, despite lesser water quality. Groundwater pumping, even in brackish zones of an aquifer, has the potential to depressurize the water bearing formation and/or even create mixing between zones in the aquifer with contrasting water quality. Therefore, pumping from these zones of the aquifers were included in the study as a precaution.

4.2.2 Spatial Correlation of SDR wells to FracFocus database

The distance between each HF well to the nearest frack supply well ranged from 0 to 90 km. The average distance was 2.3 km. Despite a standard deviation of approximately 7 km, over 82% of HF wells are within 4 km of its assigned rig/frack supply well (Figure 4-5). Network analysis generated 1,419 polygons, one for each rig/frack supply well, that function similar to a “catchment zone” for any HF event (Figure 4-6). HF catchment zone areas ranged from $1.5x10^{-5}$ km^2 to 0.92 km^2, and average $6.5x10^{-3}$ km^2. Similar to the distribution range found between HF wells and rig/frack supply wells, the largest catchment zones are found surrounding the outer boundary of the Eagle Ford. Despite the variation in catchment zone areas, over 92% of catchment zones have less than 8.0×10^{-3} km^2. Areas with a higher density of frack supply wells coincide with elevated HF events.

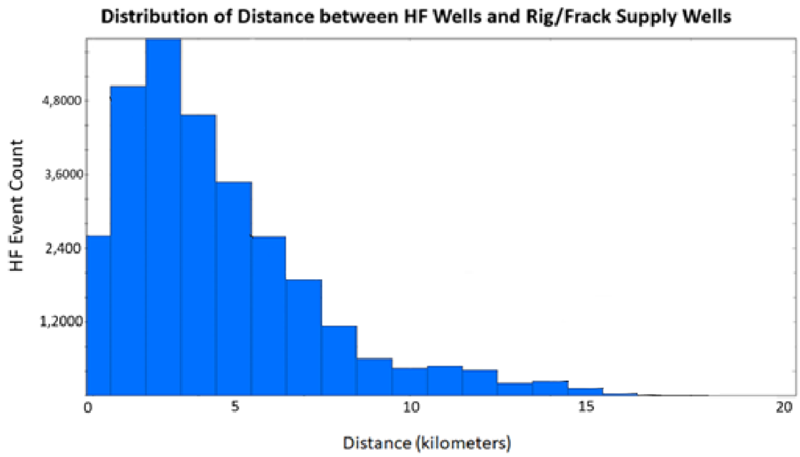


Fig 4-5: Distance distribution results from near analysis between HF events and rig/frack supply wells.

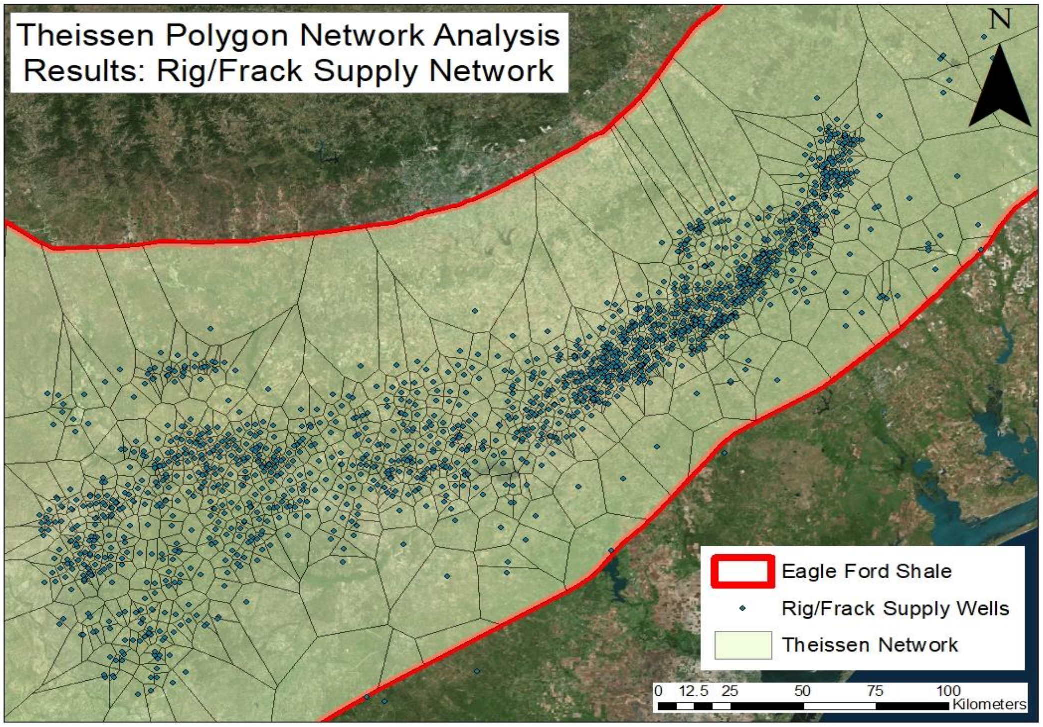


Fig 4-6: Theissen Polygon network analysis on rig/frack supply wells in the Eagle Ford Shale.

Approximately 78% of rig/frack supply wells were located within 3 km to other rig/frack supply wells (Figure 4-7). Given the close proximity, drawdown in rig/frack supply wells from the same sector are expected to occur occasionally as predicted for other sector wells. In contrast to other sector wells, however, pumping to supply for HF is short-lived, often lasting for only 9 days, with a median and standard deviation of 6 and 13 days. Therefore, the overlap of these ephemeral drawdown cones would be rare. When it does occur, however, the law of superposition predicts that drawdown magnitudes will be simply additive. This phenomenon would tend to occur more frequently in areas of intense oil and gas production.

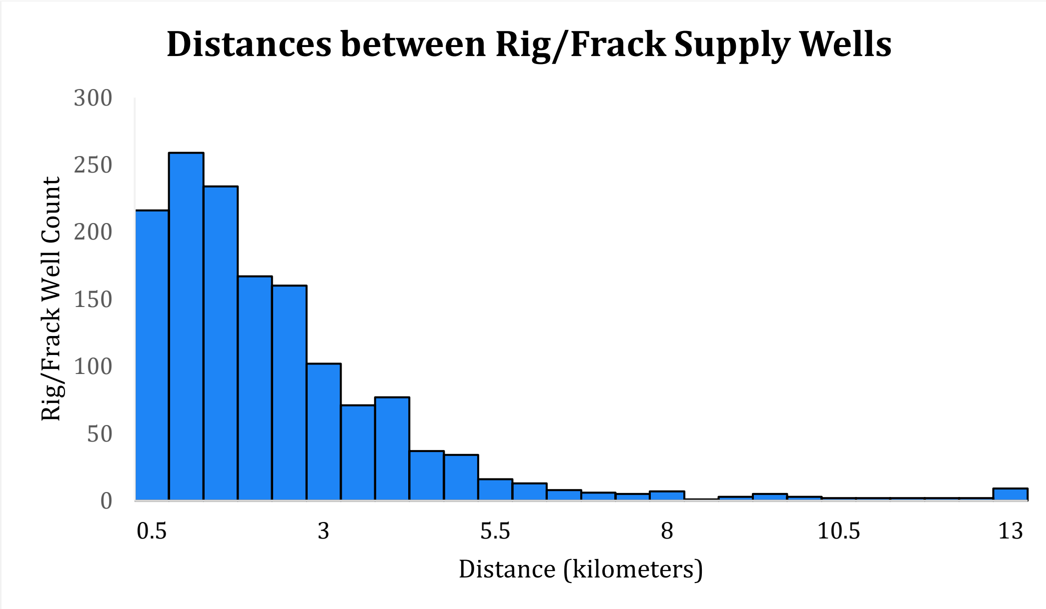


Fig 4-7: Rig/frack supply well spacing distribution to nearest rig/frack supply well.

4.2.3 Spacing between Rig/Frack Supply wells and wells from other sectors

To identify wells from other sectors potentially located within the vicinity of ephemeral drawdown cones in the Carrizo-Wilcox aquifer system created by pumping for HF, spatial analysis was performed which revealed that domestic wells were most likely to be impacted by pumping for HF. The median distance between rig/frack supply wells and domestic wells was found to be 1.45 km (Figure 4-8a). Livestock, industrial, agriculture, and public supply wells were located further away. The median distance between rig/frack supply wells to these wells were 2.05 km, 4.32 km, 5.95 km, and 15.32 km, respectively (Figure 4-8 b,c,d,e). The percentage of frack supply wells within 1 km of wells in other sectors were as follows: 2% (28/1147) for agriculture wells, 37% (419/1147) for domestic wells, 15% (174/1147) for industrial wells, 26% (294/1147) for livestock wells, and 0.4% (5/1147) for livestock wells (Figure 4-8). Depending on the intensity and duration of pumping for HF, the spatial extent and impacts of drawdown will be highly variable.

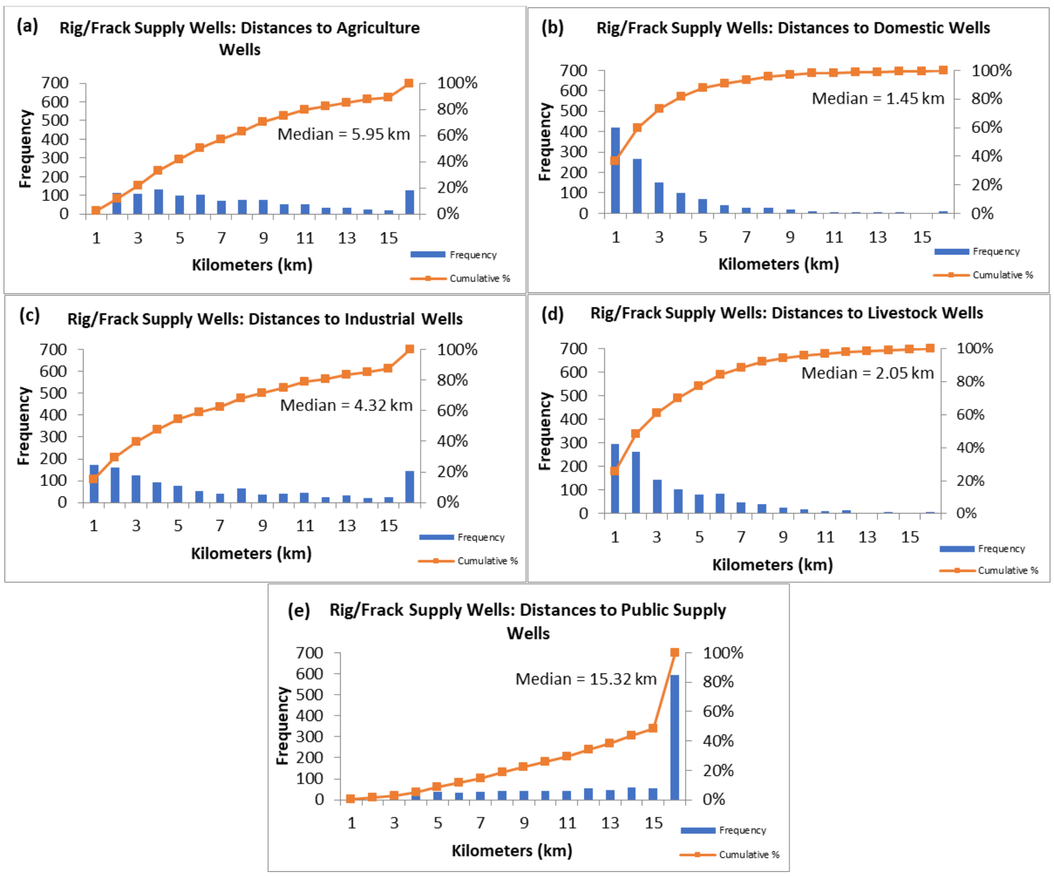


Fig 4-8: Nearest distance distribution results from near analysis. Distance distribution was calculated using frack supply wells as the stationary reference to calculate the nearest distance between from a domestic well (a), irrigation well (b), public supply wels (c), industrial well (d), and livestock well (e).

4.3 Annualized Aquifer Drawdown Model

4.3.1 Annual drawdown impacts on wells and land types by sector

Land impact analysis in the EF was performed using the annualized average modeled drawdown in the Carrizo-Wilcox aquifer system for all active GCD years. Utilizing the raster calculator in ArcGIS, the average of annualized drawdown for all active years resulted in a whole number integer. Therefore, statistics on the impacted land types are only reporting the land areas impacted by an average drawdown greater than 0.5 m. These sub-meter values are included in the 1 m drawdown bin. Annualized average drawdown less than 0.5 m is not considered in the land impact analysis. The land types spatially overlying annualized average drawdown reveal that among the six major GCDs examined, drawdown from pumping for HF occurred consistently in lands classified as 'Barren/Shrubland', 'Pasture/Hay', 'Forest', and 'Grassland'.

The top three land classifications for wells already existing within the region are summarized as follows: 1) the percentage of all domestic wells occurring in 'Pasture/Hay', 'Barren/Shrubland', and 'Developed' type land, were 35%, 33%, and 7%, respectively; 2) the percentage of irrigation wells in 'Pasture/Hay', 'Barren/Shrubland', and 'Cultivated Crop' land, are 29%, 29%, and 17%, respectively; 3) the percentage of public supply wells in 'Barren/Shrubland', 'Pasture/Hay', and 'Grassland', are 36%, 22%, and 12%, respectively; 4) the percentage of industrial wells in 'Pasture', 'Barren/Shrubland', and 'Cropland' land, are 35%, 41%, and 17%, respectively;

and lastly 5) the percentage of livestock wells in ‘Barren/Shrubland, ‘Pasture/Hay’, and ‘Grassland’ at 47%, 27%, and 14%, respectively.

4.3.1.1 Evergreen UWCD

Annualized modeled drawdown in Evergreen UWCD revealed greatest drawdown occurred in both 2014 and 2017, reaching 14 m (Figure 4-9). Modeled drawdown in 2017 underlaid an area of approximately 470 km^2, whereas drawdown in 2014 underlaid an area of only 120 km^2.

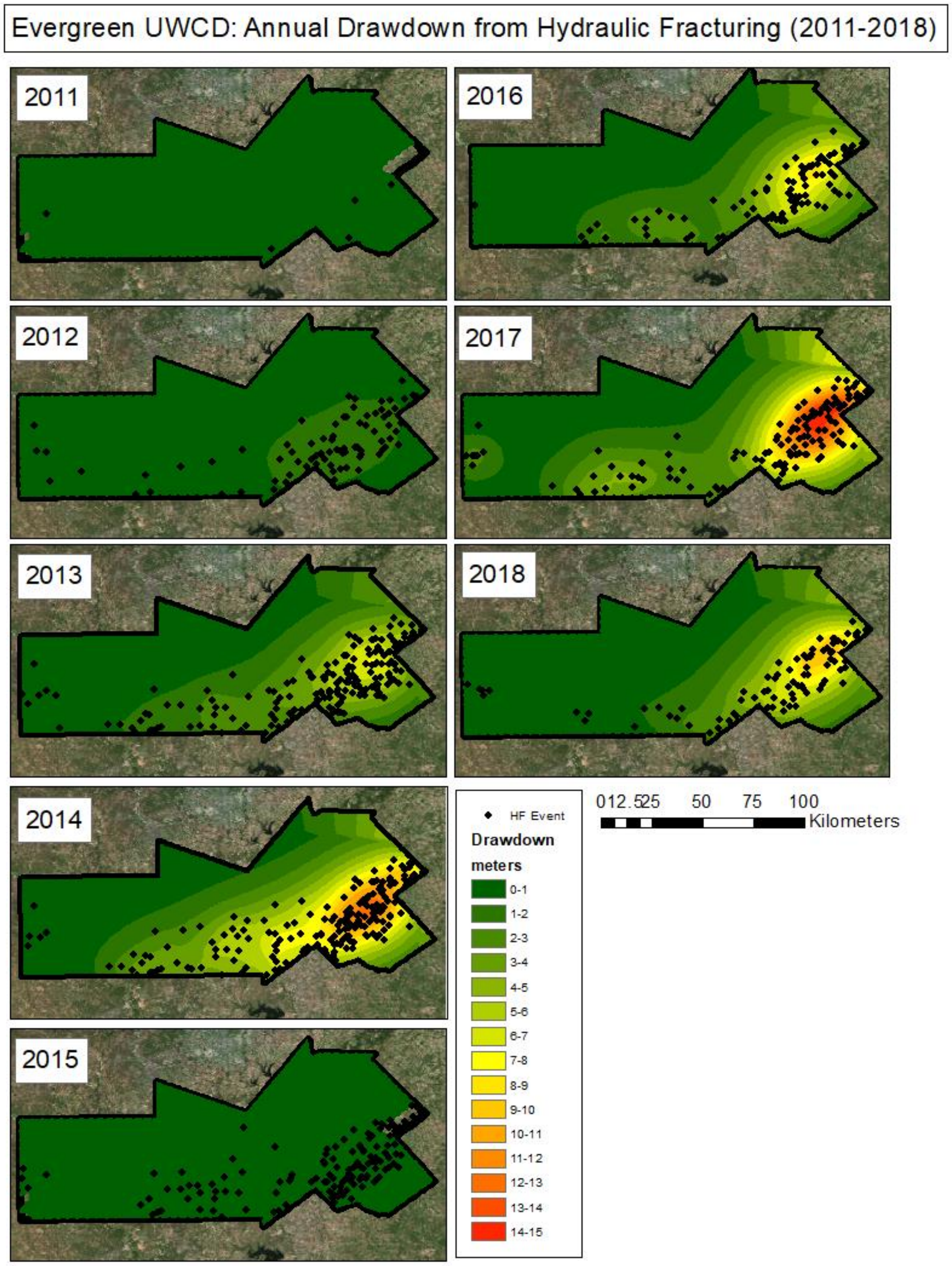


Fig. 4-9: Annualized drawdown in Evergreen UWCD driven by groundwater pumping to supply for HF.

Land impact analysis in Evergreen UWCD revealed that 50.3% of the area was affected by annualized average drawdown between 1-6 m (Figure 4-10). Among this drawdown, ‘Barren/Shrubland’ and ‘Pasture/Hay’ had the highest land area within each drawdown level, at 52% and 62% of their total land area within the district. In contrast, both ‘Barren/Shrubland’ and ‘Pasture/Hay’ comprised 22% and 16% of the district’s impacted land area, respectively. Interestingly, ’Grassland’ and ‘Cultivated Crop’ land were the next two land types most affected by annualized average drawdown, being 50% and 28% of their total land area overlying at least 1 m of drawdown. In summary, only 2% of the district’s total land area coincides spatially with the highest magnitude of average drawdown, at 6 m (Table 4-2). However, although a majority of these land types made up a small portion of the total impacted land area, the proportion of each land area to its own land type are considerable (Grassland, Cultivated Crop).

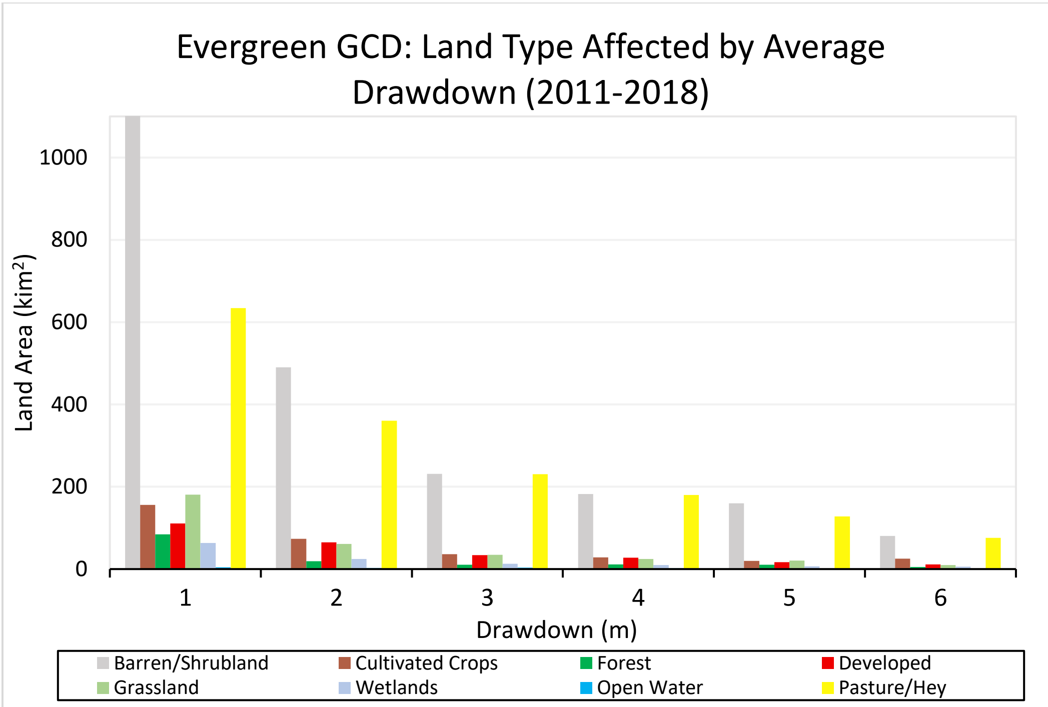


Fig. 4-10: Land types impacted by the levels of average drawdown in Evergreen GCD.

Table 4-2: Land area affected by average drawdown and its proportion to total land area in Evergreen GCD.

Drawdown (m)	1	2	3	4	5	6	Percent Land of Total Area
	Land Area Type (km^2)						
Barren/Shrubland	1112.1	490.1	231.7	182.3	159.9	80.8	22.4
Cultivated Crops	155.9	73.5	36.0	28.8	19.6	25.7	3.4
Developed	110.6	65.1	34.2	27.8	17.1	11.7	2.6
Forest	84.3	19.4	10.5	11.5	10.5	5.1	1.4
Grassland	180.9	61.2	34.8	24.3	20.8	9.5	3.3
Open Water	4.7	2.7	3.3	1.9	1.2	0.2	0.1
Pasture/Hey	634.5	360.3	230.3	180.4	128.3	75.6	15.9
Wetlands	63.2	24.7	13.2	9.9	6.4	6.2	1.2
Percent land impacted by drawdown magnitude	**23.2**	**10.9**	**5.9**	**4.6**	**3.6**	**2.1**	**50.3** **Total Area (km^2) = 10,095**

4.3.1.2 Gonzales UWCD

Groundwater pumping for HF in Gonzales County UWCD spanned from 2012 to 2018 (Fig. 4-9). During this time, the majority of annualized drawdown ranged from 0 to 1 m. During the most active HF pumping year in 2014, Gonzales County UWCD experienced a maximum annualized drawdown of only 5 m. This drawdown is localized in the southern corner of the district and propagates less than 1 km from its source. A drawdown level of 2 m underlaid an area of 400 km^2 surrounding the localized area of maximum annualized drawdown for the year 2014.

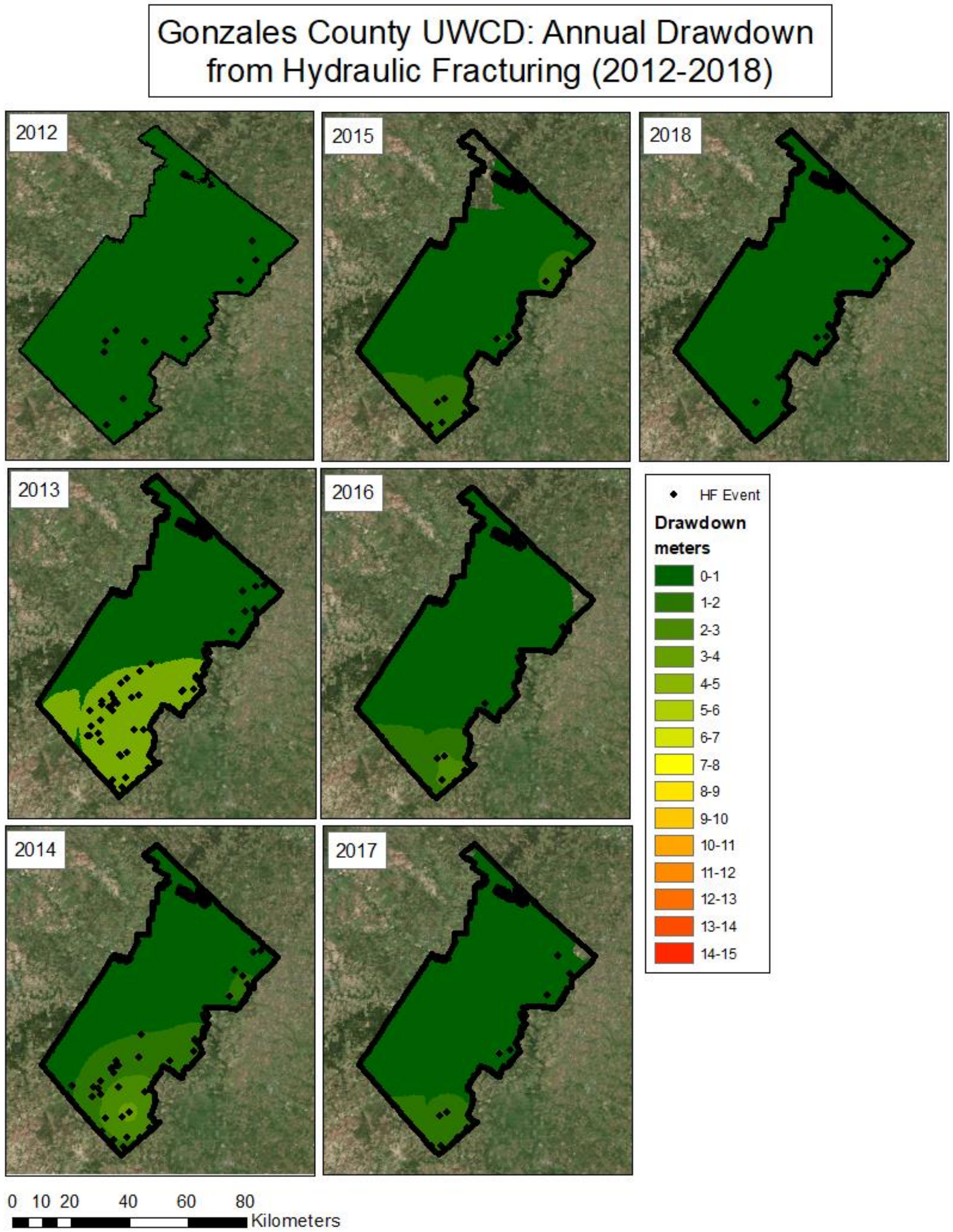


Fig. 4-11: Annualized drawdown in Gonzales UWCD driven by groundwater pumping to supply for HF.

Gonzales County UWCD experienced comparatively lower drawdown than compared to other GCDs, with approximately 11% of its total area affected by 1-2 m drawdown (Table 4-2). 'Barren/Shrubland', 'Pasture/Hay', and 'Forest' are the top three land types impacted by annualized average drawdown (Figure 4-15). Less than 1% of the district's total land area overlaid an annualized average drawdown of 2 m, revealing the impacts from groundwater pumping for HF were minimal. If high groundwater competition is occurring, it will likely be in concentrated zones at the southernmost boundary. This land analysis suggests that competition from pumping for HF is minimal in Gonzales GCD.

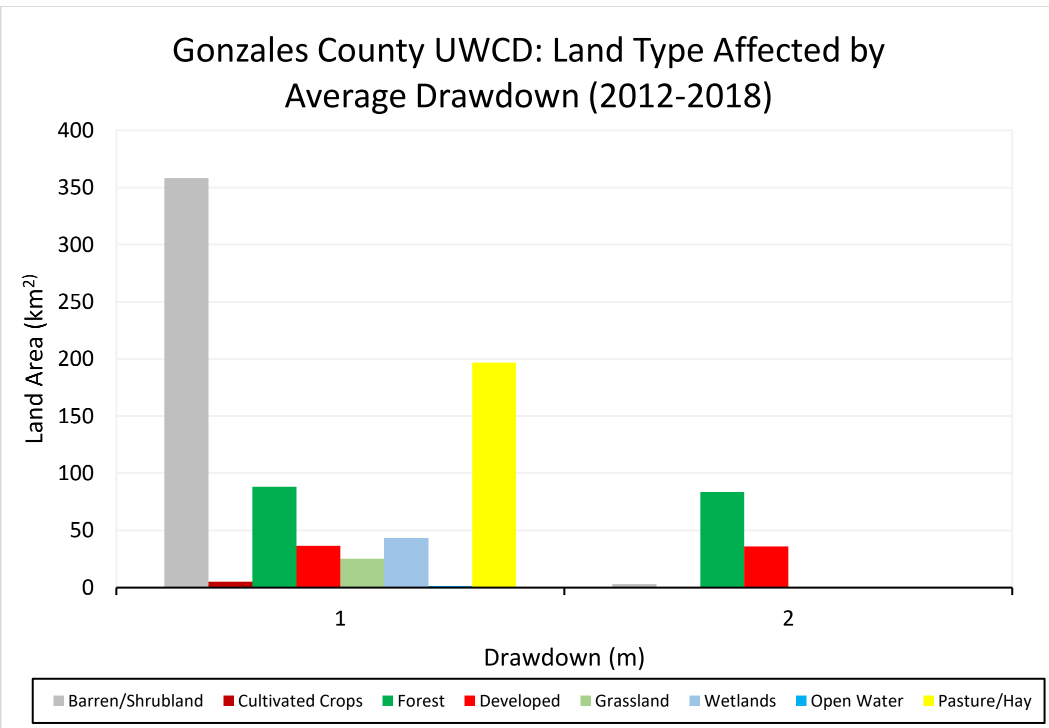


Fig. 4-12: Land types impacted by the levels of average drawdown in Gonzales County UWCD.

Table 4-3: Land area affected by average drawdown and its proportion to total land area in Gonzales County UWCD.

Drawdown (m)	1	2	Percent Land of Total Area
	Land Type Area (km^2)		
Barren/Shrubland	358.2	3.0	5.2
Cultivated Crops	4.9	0.0	0.1
Developed	36.5	36.0	1.0
Forest	88.3	83.4	2.5
Grassland	25.3	0.0	0.4
Open Water	1.4	0.0	0.0
Pasture/Hay	196.9	0.3	2.8
Wetlands	43.0	0.0	0.6
Percent land impacted by drawdown magnitude	**10.79**	**1.75**	**12.55**
			Total Area (km^2) = 6,990

4.3.1.3 Live Oak UWCD

Similar to Gonzales County UWCD, Live Oak UWCD experienced comparatively little drawdown in response to HF between the years 2011 to 2017 compared to Evergreen UWCD (Fig. 4-10). Drawdown occurred in the northernmost region of the district. Annualized drawdown reached a maximum in 2014 at 3 m over an area of approximately 200 km ^{2}. Following this high, annualized drawdown from HF decreased in 2015 and 2016, but increased again in 2017. Maximum drawdown in 2017 reached 3 m in a small area that covered 3 km^2 in the northern part of the district.

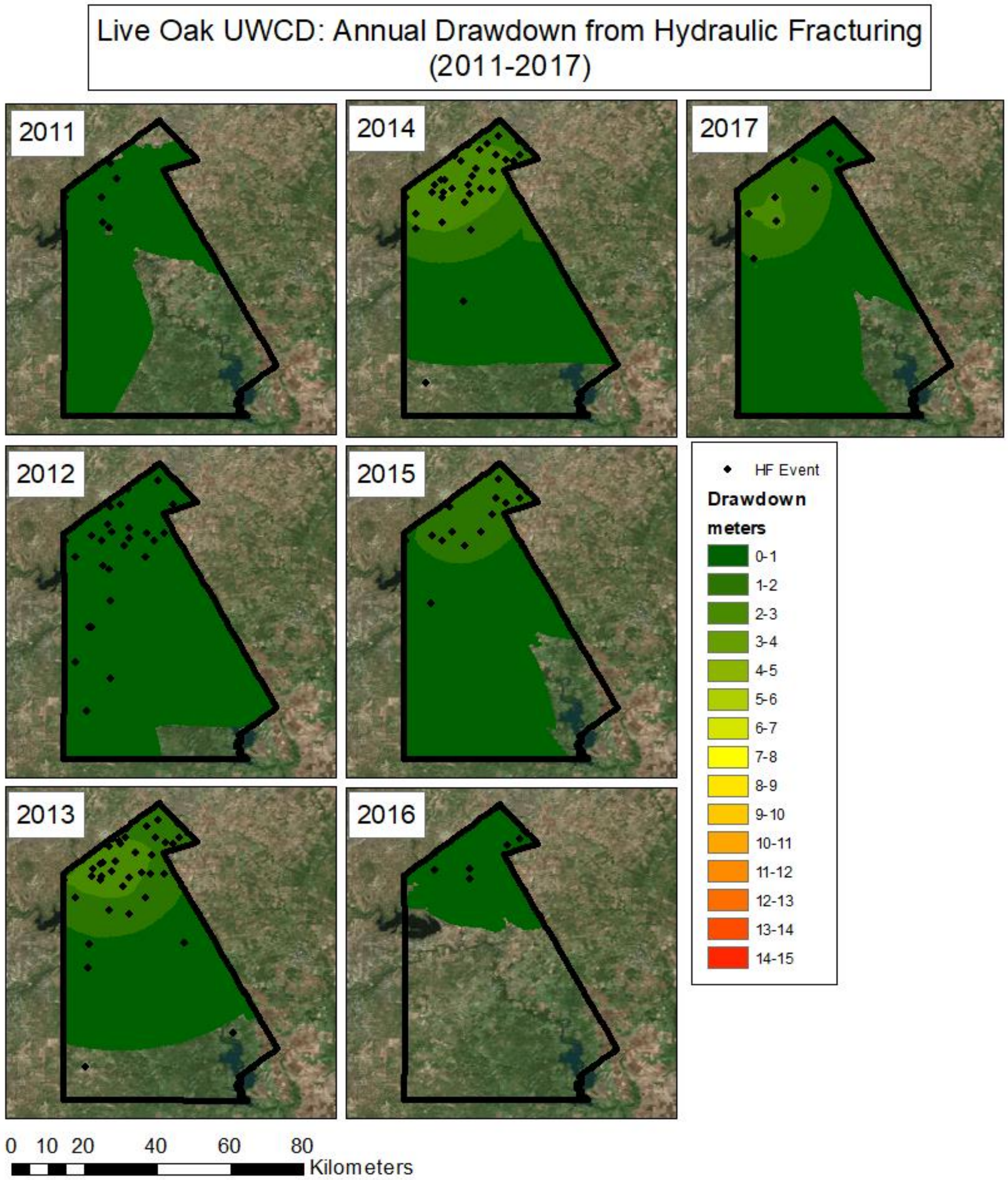


Fig. 4-13: Annualized drawdown in Live Oak UWCD driven by groundwater pumping to supply for HF.

Annualized average drawdown in Live Oak GCD reached a maximum of 1 m that extends approximately 18% over the district's land area (Table 4-3). 'Barren/Shrubland, 'Pasture/Hay', and 'Grassland' are the top three land types within annualized average drawdown, consisting of 11%, 4%, and 1% the total land area, respectively (Figure 4-16). The majority of land coinciding with drawdown was located in the northern portion of the district. Therefore, suggesting that if there was any groundwater competition occurring within the district it would be confined to the northern part of the district. Average annualized drawdown between the years 2011 to 2017 suggest groundwater demand for HF was not spatially intense nor temporally enduring to create groundwater competition among the different stakeholders in Live Oak UWCD.

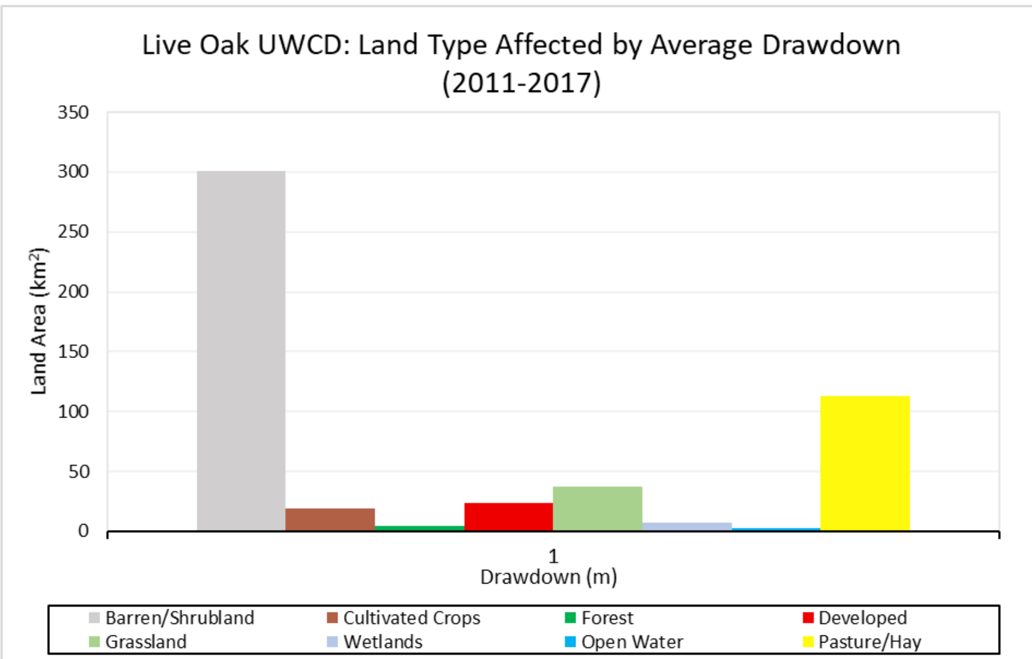


Fig. 4-13: Land types impacted by the levels of average drawdown in Live Oak UWCD.

Table 4-4: Land area affected by average drawdown and its proportion to total land area in Live Oak UWCD.

Drawdown (meters)	1	Percent Land of Total Area
	Land Type Area (km^2)	
Barren/Shrubland	301.3	10.8
Cultivated Crops	18.7	0.7
Developed	23.6	0.8
Forest	4.4	0.2
Grassland	37.6	1.3
Open Water	2.9	0.1
Pasture/Hay	113.2	4.1
Wetlands	7.2	0.3
Percent land impacted by drawdown magnitude	**18.3**	**18.3** **Total Area (km^2) = 2,790**

4.3.1.4 McMullen GCD

Between the years 2011 to 2018, approximately 69% of McMullen GCD experienced an annualized average drawdown ranging 1-4 m (Table 4-4). During this time, ‘Barren/Shrubland’, ‘Pasture/Hay’, and ‘Grassland’ were the top three land types affected for each interval of drawdown (Figure 4-17). Approximately 14% of the total land area overlaid the parts of the aquifer experiencing the maximum drawdown of 4 m, followed by 19%, 16%, and 21% land area that coincided with 3, 2, and 1 m of drawdown, respectively. Whereas the magnitude of drawdown within McMullen GCD appeared to be minimal beneath cultivated cropland, the area of total cropland that overlaid parts of the aquifer that experienced 1-4 m of drawdown was 62% of cropland total area. Thus, groundwater pumping for HF coincided spatially with a majority of cropland within McMullen GCD. At a maximum drawdown level of 4 m, only 10% of 'Cultivated Crops' land overliad this drawdown extent, followed by 5% within 3 m, 19% within 2 m, and 27% within 1 m of drawdown.

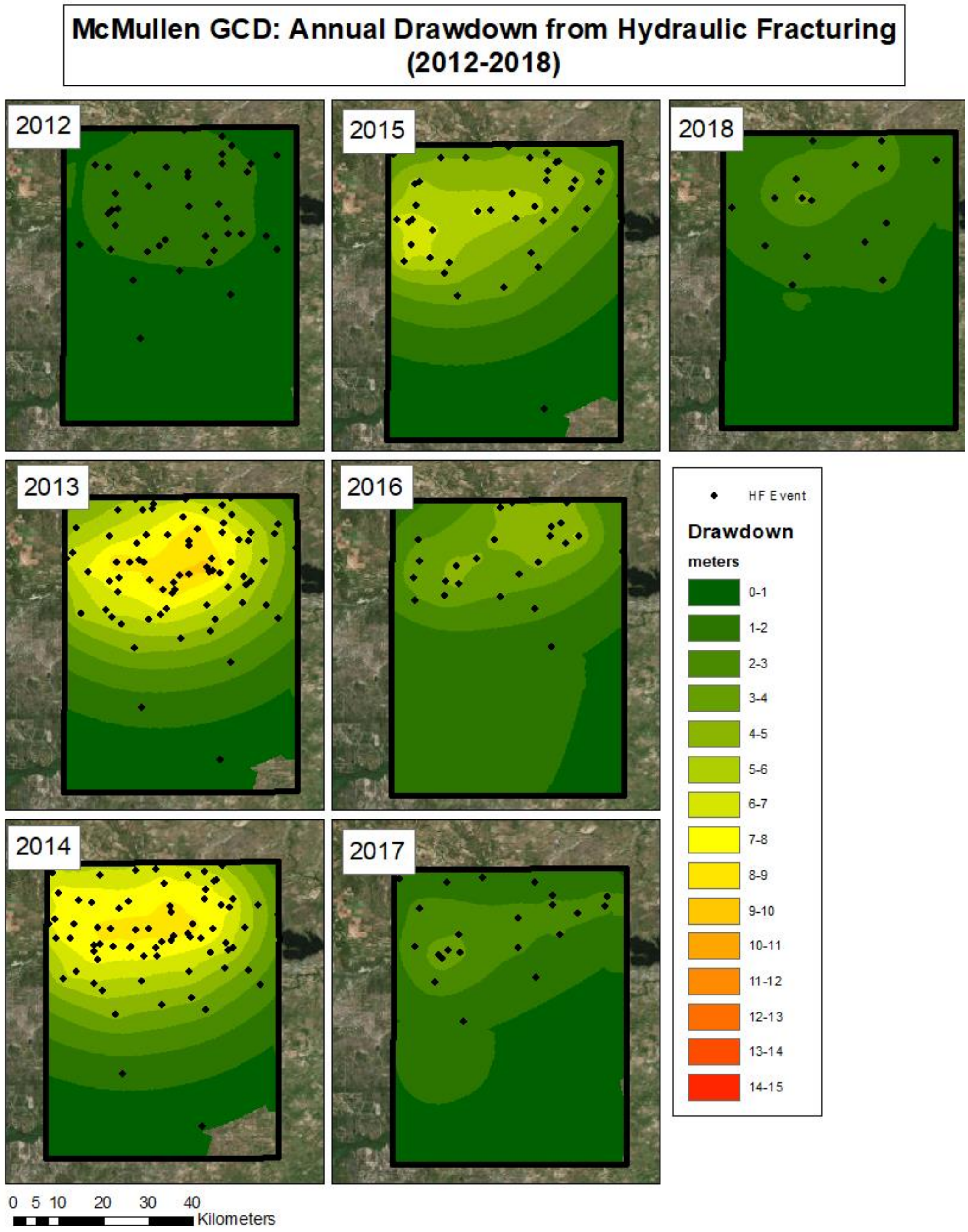


Fig. 4-14: Annualized drawdown in McMullen driven by groundwater pumping to supply for HF.

Although the modeled impacts from past groundwater pumping for HF were minimal, there is potential for future groundwater competition if water demand for HF became more intense or temporally continuous. Concentrated high drawdown in priority land types or more widespread drawdown of a lower magnitude is more likely to impact stakeholders due to their proximity to HF groundwater pumping.

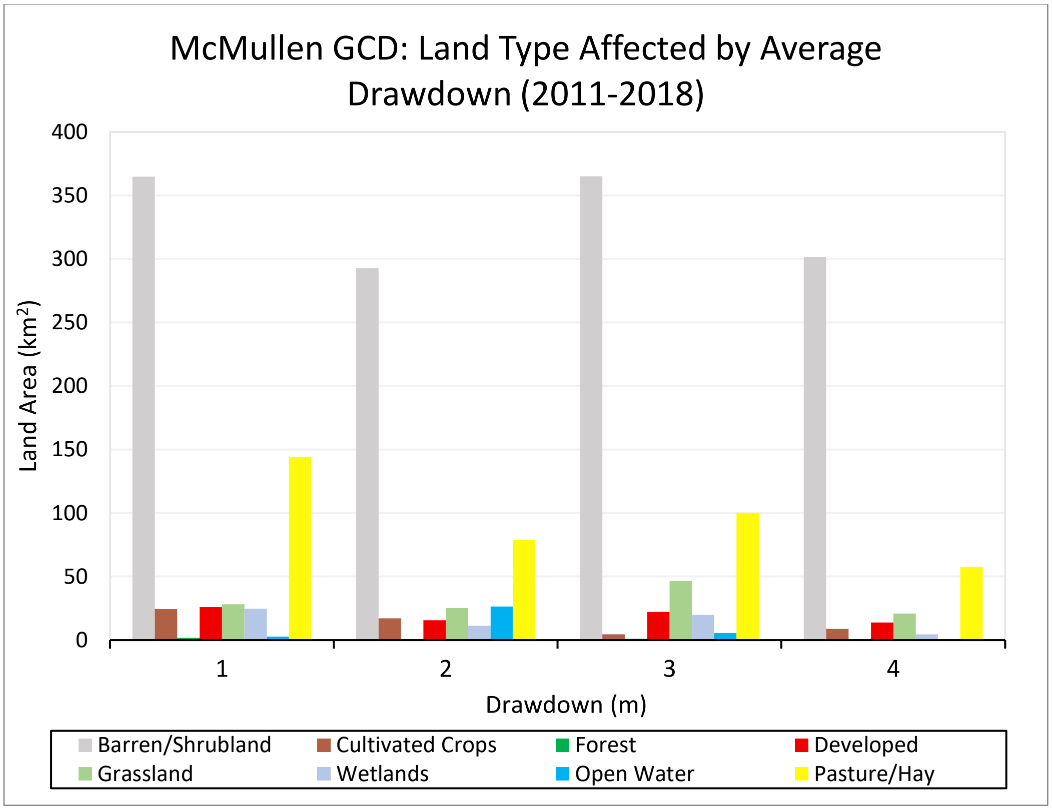


Fig. 4-15: Land types impacted by the levels of average drawdown in McMullen GCD.

Table 4-5: Land area affected by average drawdown and its proportion to total land area in McMullen GCD.

Drawdown (m)	1	2	3	4	Percent Land of Total Area
	Land Type Area (km^2)				
Barren/Shrubland	364.7	293.2	363.3	299.5	44.0
Cultivated Crops	24.4	17.2	4.5	9.0	1.8
Developed	25.9	15.8	22.5	14.1	2.6
Forest	1.9	1.6	2.0	1.8	0.2
Grassland	28.3	25.1	46.5	21.0	4.0
Open Water	2.7	26.5	5.5	0.6	1.2
Pasture/Hay	143.9	78.9	100.2	57.8	12.7
Wetlands	24.7	8.2	11.7	7.1	1.7
Percent land impacted by drawdown magnitude	**20.5**	**15.6**	**18.5**	**13.7**	**68.3** **Total Area (km^2) = 3,000**

4.3.1.5 Pecan Valley GCD

Pecan Valley GCD experienced the largest annualized drawdown compared to the other GCDs, with as much as 18 m in 2014 and 2015 (Figure 4-12). Although the magnitude of this drawdown was the largest across the GCDs, its spatial extent was comparatively small. This area underlaid approximately 8 km^2 in the northwestern boundary of the GCD and was encompassed by an area of approximately 25 km^2 of 10 m annualized drawdown. After 2014, drawdown levels decreased but remained primarily within the range of 4-10 m. It is important to note that this region is known to be a highly productive zone of the EF and that production rates are generally known to be less affected by fluctuations in oil and gas prices. The less drastic reduction in annualized drawdown for 2015 for Pecan Valley GCD may be an example of past reports from oil and gas operators that migrate to more profitable zones during periods with low oil and gas prices (Hiller, 2013).

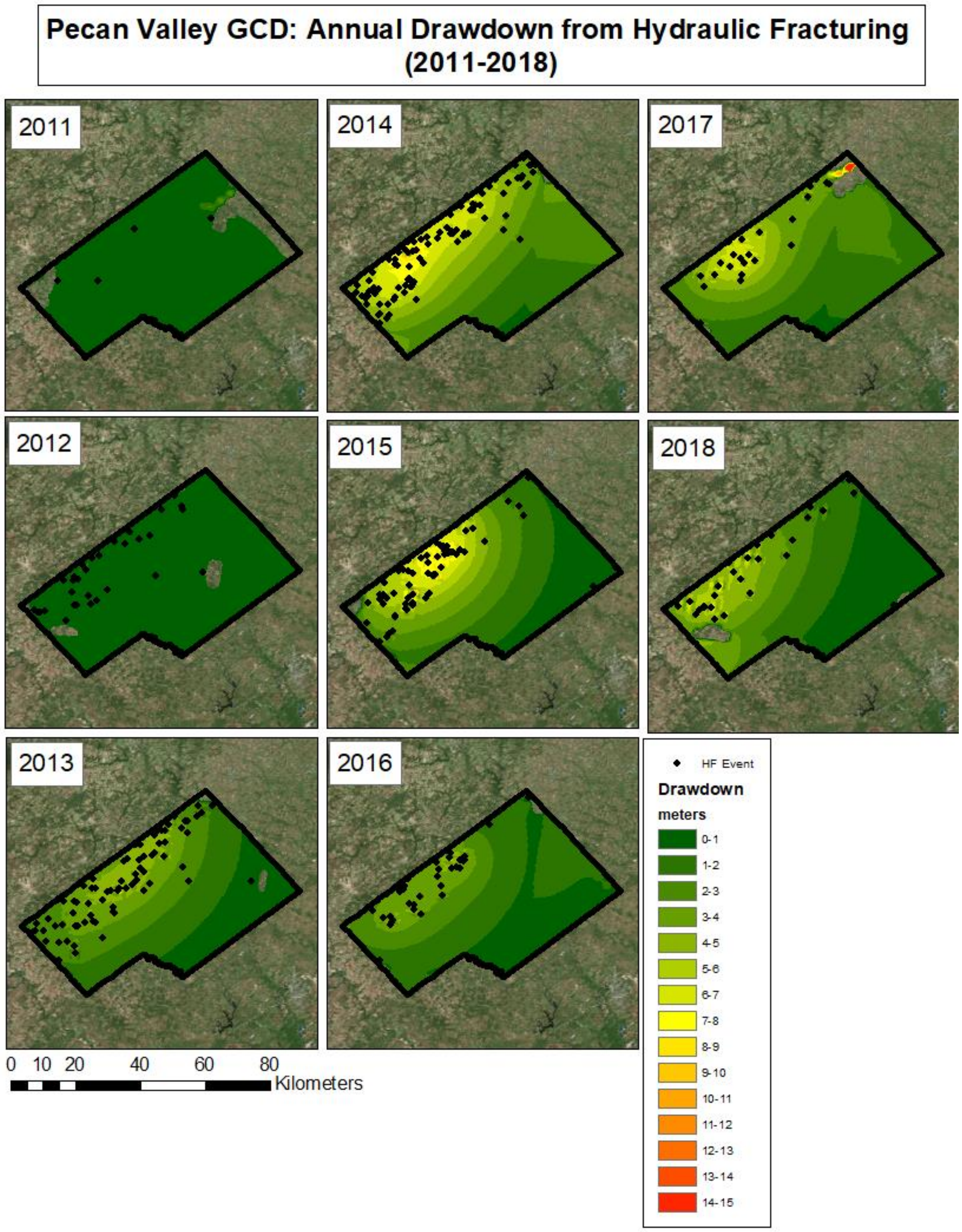


Fig. 4-16: Annualized drawdown in Pecan Valley GCD driven by groundwater pumping to supply for HF.

Having experienced one of the highest maximum levels of modeled average drawdown, a total of 73% of Pecan Valley GCD land area coincided with drawdown ranging from 1-5 m (Table 4-5). Of this land area, ‘Pasture/Hay’, ‘Barren/Shrubland’, and ‘Deciduous Forest’ land were the top three types that spatially coincided within drawdown, followed by ‘Developed, Open Space’ and ‘Cultivated Crops’ (Figure 4-18). Whereas less than 1% of total land area affected was within a maximum drawdown of 5 m, 5.3% is within 4 m, 15% was within 3 m, 18% was within 2 m, and 34% was within 1 m of drawdown. Despite highly localized drawdown, the major land areas within the extent of 1-5 m drawdown made up a large portion of their total area within the district. The percentage of each land type affected by 1-5 m of drawdown relative to its total land type area within the GCD were as follows: 1) 72% ‘Pasture/Hay’; 2) 81% ‘Barren/Shrubland’; 3) 64% ‘Deciduous Forest’; 4) 70% ‘Developed’; and 5) 92% ‘Cultivated Crops’.

Similar to McMullen GCD, these results suggest a high potential for groundwater competition among stakeholders. The most dramatic impacts in the case of HF water use intensifying or becoming more temporally continuous would be expected within cultivated croplands, owing to its close proximity to pumping for HF. Other land includes ‘Developed’ due to its close connection accommodating human demands, and ‘Pasture/Hay’ because of livestock demands and due to many wells of various other sectors residing on this land type.

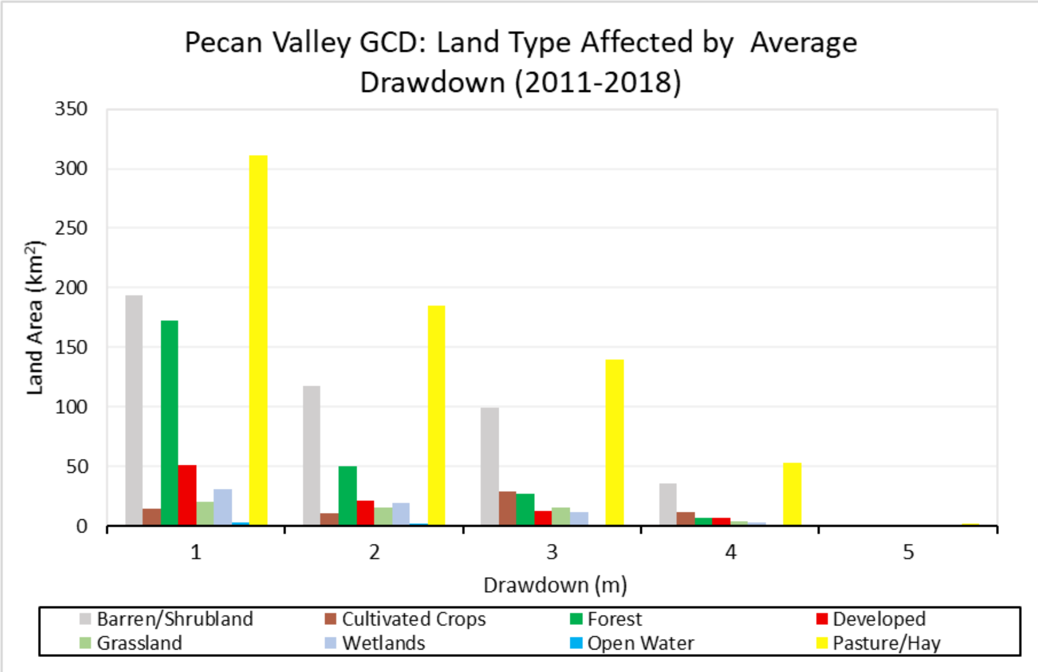


Fig. 4-17: Land types impacted by the levels of average drawdown in Pecan Valley GCD.

Table 4-6: Land area affected by average drawdown and its proportion to total land area in Pecan Valley GCD.

Drawdown (m)	1	2	3	4	5	Percent Land of Total Area
			Land Type Area (km^2)			
Barren/Shrubland	193.4	117.9	99.0	35.8	1.7	19.3
Cultivated Crops	15.1	10.8	29.3	11.6	0.7	2.9
Developed	51.6	21.0	13.1	6.8	0.3	4.0
Forest	172.5	50.6	26.7	7.3	0.2	11.1
Grassland	20.5	16.0	15.7	4.1	0.0	2.4
Open Water	3.0	1.8	0.3	0.0	0.0	0.2
Pasture/Hay	310.8	184.6	140.0	53.0	1.8	29.7
Wetlands	31.1	20.0	11.7	3.5	0.0	2.9
Percent land impacted by drawdown magnitude	**34.4**	**18.2**	**14.5**	**5.3**	**0.2**	**72.5** **Total Area (km^2) = 2,320**

4.3.1.6 Wintergarden GCD

Lastly, Wintergarden GCD ranks second for the greatest annualized drawdown between the years 2011 to 2018 (Figure 4-13). While still less than the maximum drawdown in Pecan Valley GCD, the spatial extent of maximum drawdown (12-14 m) covers a land area of approximately 230 km^2. The next interval of drawdown, 10-12 m, encompasses approximately 1,600 km^2. From these results, groundwater pumping for HF in this region appears to be more widespread, and intense, throughout the region than compared to annualized drawdown in Pecan Valley GCD. However, similar to Pecan Valley GCD and despite the decline in annual drawdown in 2014, the resurgence of annualized drawdown in 2017 and 2018 suggests profitable zones were still exploited during low oil and gas prices. It is important to note that within Wintergarden GCD, agriculture production mainly occurred in the north. Generally, this area is outside the footprint of EF activities, however, when HF groundwater demand is high, drawdown could potentially extend into the agriculture region with levels ranging 2-6 m (e.g. 2014).

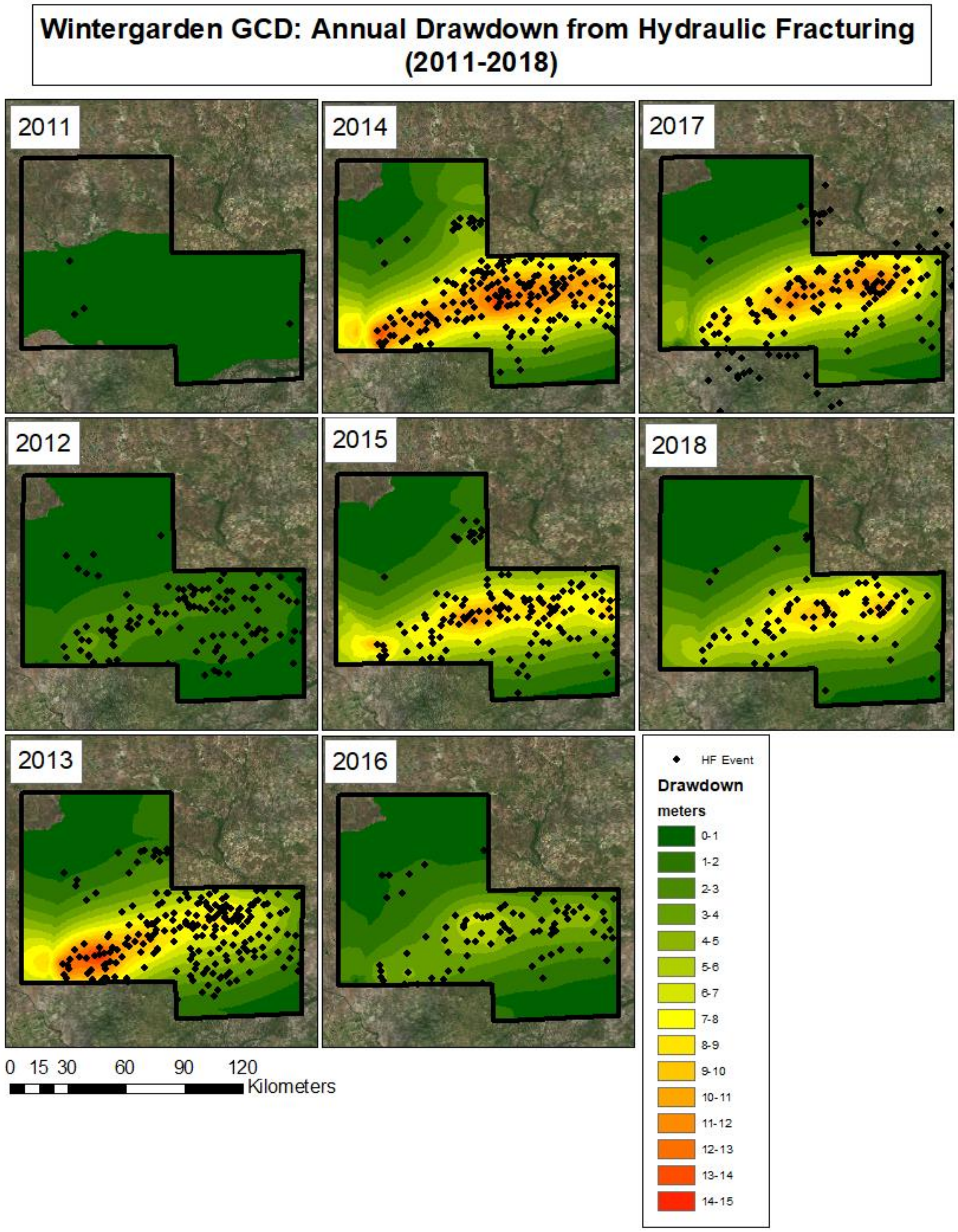


Fig. 4-18: Annualized drawdown in Wintergarden GCD driven by groundwater pumping to supply for HF.

Wintergarden GCD land impact analysis revealed annualized average drawdown between the years 2011 to 2018 to extend over 71% of the district's total land area (Table 4-6). Maximum annualized average drawdown within Wintergarden GCD is the highest out of all districts, where ‘Barren/Shrubland’, ‘Grassland’, ‘Pasture/Hay’, and ‘Cultivated Crops’ are the top four land types overlying modeled drawdown (Figure 4-19). Out of the total land area affected by drawdown, 2% coincides within 7 m of drawdown, followed by 10% in 6 m, 10% in 5 m, 12% in 4 m, 11% in 3 m, 10% in 2m, and 17% in 1 m drawdown. The major land areas listed above reveal a high proportion of their total land type area to be within drawdown, suggesting the potential for elevated groundwater competition with increased HF water demand. The proportion of each major land type within drawdown are as follows: 1) 70% ‘Barren/Shrubland’; 2) 85% ‘Grassland’; 3) 81% ‘Pasture/Hay’; and 4) 50% ‘Cultivated Crops’. Although Wintergarden GCD is considered one of the more active regions for agriculture, its proportion of cropland overlying modeled drawdown is comparatively lower than in other districts, such as Pecan Valley GCD or McMullen GCD, but still a large proportion. As described earlier, Wintergarden GCD displays more consistent annualized drawdown over the years than other districts, suggesting the region is economically productive, even during unfavorable oil and gas prices. This very quality of the region is predicted to be a major driving force in determining the extent and magnitude of groundwater competition among local stakeholders, which is why their proximity to HF groundwater pumping should be an important feature to account for.

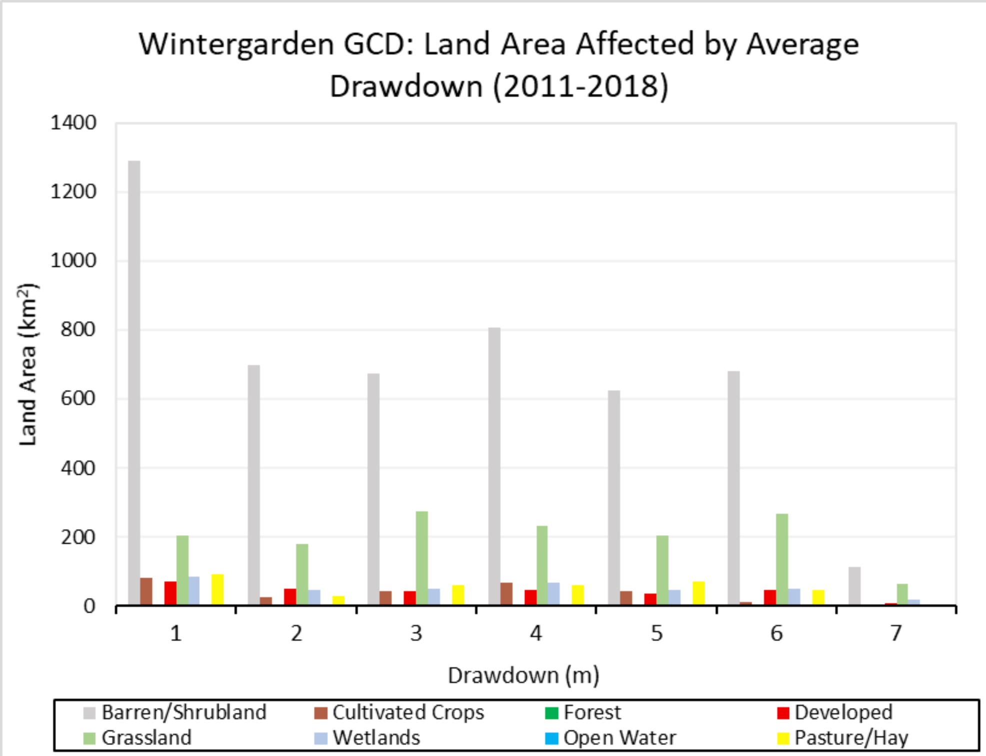


Fig. 4-20: Land types impacted by the levels of average drawdown in Wintergarden GCD.

Table 4-7: Land area affected by average drawdown and its proportion to total land area in Wintergarden GCD.

Drawdown (m)	1	2	3	4	5	6	7	Percent Land of Total Area
	Land Type Area (km^2)							
Barren/Shrubland	1289.0	697.1	674.7	805.7	623.0	681.8	111.1	45.9
Cultivated Crops	80.9	24.2	43.3	67.8	40.9	12.0	1.1	2.5
Developed	71.1	50.4	42.8	44.7	36.5	44.9	6.3	2.8
Forest	5.4	0.3	2.2	5.2	3.8	2.5	1.1	0.2
Grassland	202.1	178.1	272.9	231.5	201.8	265.6	64.0	13.3
Open Water	1.9	0.3	0.5	1.4	0.3	1.9	0.3	0.1
Pasture/Hay	89.9	28.3	58.6	58.3	70.6	44.7	2.7	3.3
Wetlands	83.6	45.8	47.9	66.7	45.2	48.2	17.7	3.3
Percent land impacted by drawdown magnitude	**17.1**	**9.6**	**10.7**	**12.0**	**9.6**	**10.3**	**1.9**	**71.4** Total Area (km^2) = 10,650

In summary, annualized drawdown among the 6 GCDs ranged from 0-18 m from 2011 to 2018. Of these, Live Oak UWCD and Gonzales County UWCD experienced the least drawdown, remaining less 5 m during the study period, while the other districts experienced maximum drawdown greater than 10 m during the study period. Evergreen UWCD and Wintergarden GCD experienced the greatest magnitude of annual drawdown, at 15 m.

Results of well sectors impacted by the greatest 5% of annual drawdown revealed wells in Evergreen UWCD and Wintergarden GCD experienced the greatest magnitude of drawdown than compared to other GCDs. Within Evergreen UWCD, the sector impacted by the greatest 5% of drawdown were livestock wells, where 22% (35/162) of wells were impacted by an annual drawdown of 6.63 m. The remaining sector wells impacted by drawdown are as follows: 1) 7% (1/14) of public supply wells, impacted by 2.93 m of drawdown; 2) 5% (4/77) of agriculture wells, impacted by 1.74 m of drawdown; 3) 5% (38/753) of domestic wells, impacted by 2.12 m; and 4) 5% (3/66) of industrial wells, impacted by 3.56 m of drawdown.

The greatest magnitude of annual drawdown to impact sector wells in Wintergarden GCD was found to be 7.66 m, experienced by livestock wells. This magnitude of drawdown impacted 5% (10/185) of the livestock wells in the district. The remaining wells impacted in Wintergarden GCD are as follows: 1) 4% (1/23) of industrial wells, impacted by 6.61 m of drawdown; 2) 5% (1/22) of agriculture wells, impacted by 6.87 m of drawdown; 3) 5% (8/155) of domestic wells, impacted by 6.92 m of drawdown; and 4) 50% (1/2) pf public supply wells, impacted by 5.75 m of drawdown.

Wells impacted by rig/frack supply well pumping in Gonzales UWCD, Live Oak UWCD, McMullen GCD, and Pecan Valley GCD experienced comparatively lower drawdown than Evergreen UWCD and Wintergarden GCD. Out of these GCDs, livestock wells in Pecan Valley GCD were impacted the greatest in proportion to its total well population in the district, at 6% (9/177) of wells. These wells experienced the greatest 5% annual drawdown of 4.90 m. The highest percentages of wells impacted in the remaining district are as follows: 1) 14% (1/7) of livestock wells impacted by 1.94 m of drawdown in Gonzales UWCD; 2) 6% (2/33) of industrial wells impacted by 1.68 m of drawdown in Live Oak UWCD; and 3) 3% (3/94) of livestock wells impacted by 4.80 m of drawdown in McMullen GCD.

Table 4-8: Summary of well sectors impacted by the greatest 5% of annual drawdown in the EF over 8 years.

Annual Model: 50th/95th Percentile of 8-year Drawdown Magnitudes in Sector Wells						
	Evergreen UWCD	Gonzales UWCD	Live Oak UWCD	McMullen GCD	Pecan Valley GCD	Wintergarden GCD
Agriculture wells	0.58/1.74	0.22/0	-	2.90/3.07	-	2.86/6.87
Domestic wells	0.93/2.12	0.27/0.65	-	3.85/4.41	-	3.33/6.92
Industrial wells	1.44/3.56	-	1.50/1.62	2.56/2.98	3.51/3.51	5.04/6.61
Livestock wells	4.16/6.63	1.32/1.94	1.00/1.68	3.74/4.80	3.44/4.90	5.00/7.14
Public supply wells	0.94/2.93	0.66/0.82	-	-	-	2.40/5.75

4.4 Transient Aquifer Drawdown Model

The results of the transient drawdown model in response to groundwater pumping for hydraulic fracturing contrast with that of the annual drawdown models. Pumping for HF is relatively unique across the spectrum of sectors. Groundwater used for HF tends to be produced with high pumping rates, but for short time durations. Thus, whereas the annualized drawdown approach would be an acceptable estimate of typical drawdowns from sectors that produce water at similar rates throughout the year, this approach misses a key feature of groundwater pumping for HF. Drawdown from HF is ephemeral at any given place. Therefore, modeling time dependent drawdown is necessary to capture the drastic, but ephemeral, impacts for HF on wells in other sectors.

Before reporting the results from transient modeling, two key variables were developed to describe time: 1) study days. This is the actual length of days in real time. The length of study time was 2722 days, corresponding to April 5, 2011 as the first study day and September 17, 2018 as the last study day; 2) Drawdown days. This is referring to the number of days that all wells in a sector experienced drawdown from HF pumping. Each day that a well experienced drawdown was counted as one drawdown day. For example, if there were 100 study days of HF pumping in a district and 25 domestic wells, there would be a total of 2,500 possible drawdown days (Equation 8). However, if only 2 wells were impacted by HF every day for the whole study time, there would be 200 drawdown days.

Where:
Study Days = 100
Well count = 25

$$\text{Possible drawdown days} = Well\ count * Study\ Days \tag{8}$$
$$= 25 * 100$$
$$= 2{,}500$$

Intense groundwater pumping for HF occurred over the length of a few days to weeks. Maximum drawdown across each sector ranged from 2 m to over 300 m over the six GCD study region (Table A-2). Table 4-7 summarizes average transient drawdown over all study days and over the whole study area. Surprisingly, wells in McMullen GCD experienced some of the highest average drawdowns over the study period, while the annualized drawdown model of McMullen GCD exhibited less drawdown when compared to the other GCDs. Wells in Pecan Valley GCD and McMullen GCD experienced consistently high transient drawdown relative to other GCDs over the study period, followed by Wintergarden GCD and Evergreen UWCD (Table A-2). Out of the 2,722-day study period, the count of real time days in which at least one other sector well was impacted are as follows: 1) 1,361 in Evergreen UWCD; 2) 817 in Gonzales UWCD; 3) 790 in Live Oak UWCD; 4) 1,089 in McMullen GCD, 5) 1,280 in Pecan Valley GCD; and 6) 1,225 in Wintergarden GCD.

Table 4-9: Results of average transient drawdown experienced by wells over all study days from all 6 Groundwater Conservation Districts, from 2011 to 2018.

Average Drawdown at Wells by Sector over Total Time and Space (meters)						
	Evergreen UWCD	Gonzales UWCD	Live Oak UWCD	McMullen GCD	Pecan Valley GCD	Wintergarden GCD
Agriculture wells	-0.010	<-0.0001	-	-0.870	-0.136	-0.024
Domestic wells	-0.023	-0.001	0.000	-0.256	-0.210	-0.028
Industrial wells	-0.054	0.000	-0.004	-0.830	-0.433	-0.047
Livestock wells	-0.311	<-0.0001	-0.150	-0.331	-0.504	-0.513
Public supply wells	-0.003	-0.001	-	-	-0.281	-0.010
Well Days/Total Time	0.50	0.30	0.29	0.40	0.47	0.45

4.4.1 Transient drawdown impacts from ephemeral HF pumping

4.4.1.1 Evergreen UWCD

The well impact analysis in Evergreen GCD revealed that livestock wells assigned to the Carrizo-Wilcox aquifer system experienced the greatest additional drawdown from HF groundwater pumping compared to other sectors. For all wells, for all study days, the maximum additional drawdown in livestock wells was approximately 95 meters (Table A-3). The next greatest maximum drawdown was experienced by agriculture wells, at only 3.72 m, followed by industrial, domestic, and public supply wells, at 2.53 m, 0.01 m, and 0 m. Together, 265 wells in Evergreen UWCD experienced drawdown for approximately 27,500 drawdown days. These included 261 livestock wells, 1 domestic well, 2 industrial wells, and 1 agriculture well. No public supply wells were impacted by transient drawdown during the study period. The distribution of drawdown magnitudes that impacted wells in each sector experienced over the study period is shown in Figure 4-20. Ninety-four percent (261/277) of livestock wells were impacted by transient drawdown over the study time. The percentage of industrial wells, domestic wells, and agriculture wells impacted at some point during the study time are as follows: 1) 10% (2/20); 2) 0.25% (1/399); and 3) 0.50% (1/199). (Table A-2)

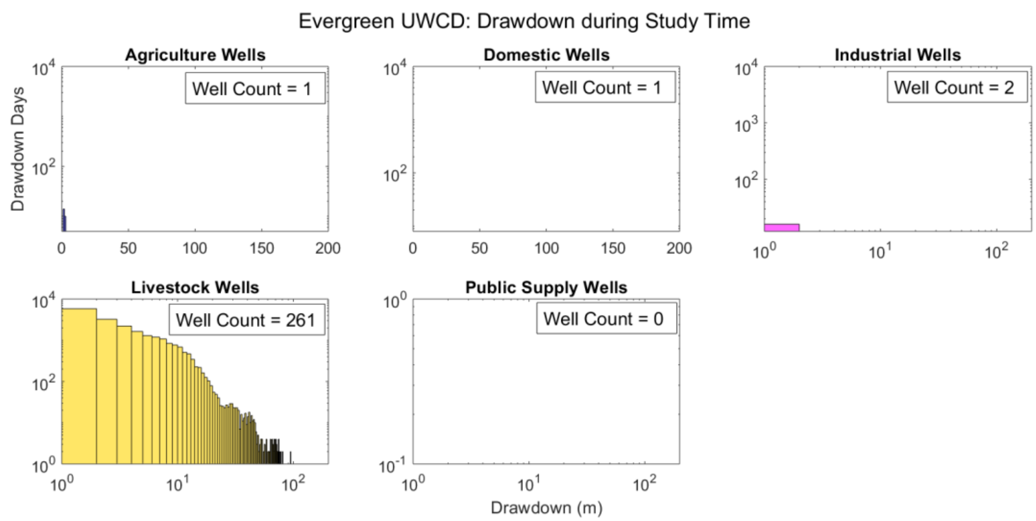


Fig 4-20: Transient drawdown levels experienced over the 8-year study period for Evergreen UWCD sector wells.

In this thesis, the severity of drawdown reports the percentage of drawdown days a given well sector in a given GCD experienced a magnitude of drawdown in the 95th percentile and greater. A severity of one signifies a given drawdown magnitude occurred in 100% of the total drawdown days. In contrast, a severity of zero signifies there was not a single day out of the drawdown days that experienced a drawdown at the given magnitude.

The severity of transient drawdown for sector wells were calculated as: 1) 5.0% in livestock wells; 2) 12.50% in domestic wells; 3) 10% in industrial wells; 4) 5.90% in agriculture wells; and 5) 0% in public supply wells. Keeping in mind that these percentages represent the proportion of drawdown days with the top 5% of experienced drawdown magnitudes, domestic wells were found to have experienced the greatest severity of drawdown, at a level greater than 0.01 m that occurred in 12.50% of the drawdown days. Although domestic wells were found to experience the greatest 5.00% of drawdown more often than wells of other sectors, livestock wells still experienced drawdown more consistently throughout the study period, approximately 84% of the time. Of the drawdown experienced by livestock wells, the 95th percentile of drawdown was over 14.95 m.

Considering daily pumped volumes and electricity cost rates for each sector in Evergreen UWCD, the predicted cost impacts over the study time revealed livestock, agriculture, and industrial wells payed an additional pumping cost of approximately $1.69. $0.95, and $0.003 per day during days of maximum drawdown, shown (Figure 4-21). Although livestock wells were previously determined to have experienced the highest magnitude of drawdown, the higher pumping rate of agriculture wells in the region offset the more extreme drawdown in livestock wells. Totaling the cost impacts from transient drawdown over the entire study period and averaging these totals across each sector, the average agriculture well owner was found to have paid \$0.50 more for their groundwater during days of drawdown, whereas livestock well owners paid \$0.04 more. Examining these costs in proportion to sector GDP revealed average additional pumping during drawdown days to amount to only 5.01×10^{-9} % of annual GDP for the agriculture industry, followed by 4.18×10^{-10} %, 3.93×10^{-13}%, and 1.56×10^{-13} % for the livestock, industrial, and domestic sectors.

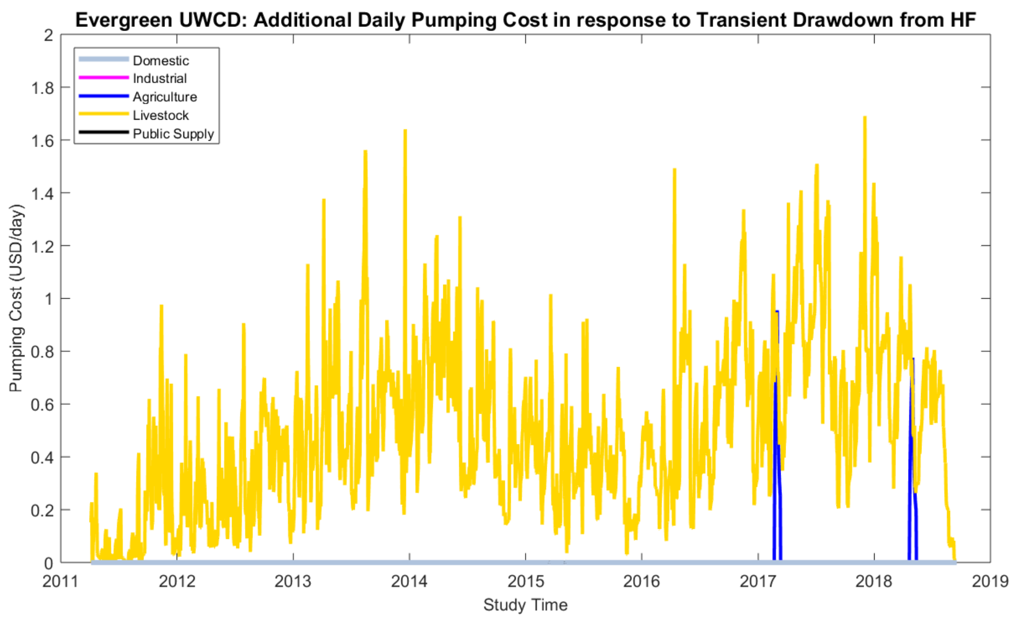


Fig 4-21: Average additional daily pumping cost for wells by sector in Evergreen UWCD over the study period.

Using the range of transient drawdown experienced by sector wells in Evergreen UWCD, pumping cost curves were created to consider socio-economic factors and daily pumped volumes (Figure 4-22) (Table A-3). From these pumping cost curves, the additional pumping cost at a given level of drawdown can be calculated with wells from any sector. Each well sector pumping cost curve estimated the additional pumping costs using the maximum transient drawdown experienced in each sector as the defining maximum cost paid.

Although livestock wells experienced the greatest magnitude of drawdown, a well owner was found to only pay an additional pumping cost of $0.59 per day at maximum drawdown. Agricultural well owners were found to pay the most for additional pumping, at a cost of $1.10 per day at maximum drawdown. Maximum additional pumping costs for the remaining well are as follows: 1) $0.08 per day for domestic wells; and less than a cent per day for industrial wells.

The single agriculture well impacted had the greatest pumping cost gradient with added drawdown, at a rate of $0.28 a day per m of drawdown. The average domestic well owner in Evergreen UWCD was estimated to pay a rate of $0.03 per m of drawdown, followed by $0.01 for livestock well owners, and less than a cent for owners of industrial wells (Figure 4-22). These pumping cost curves offer a utility to all residents within Evergreen UWCD at a resolution that other, more generalized pumping rates do not supply.

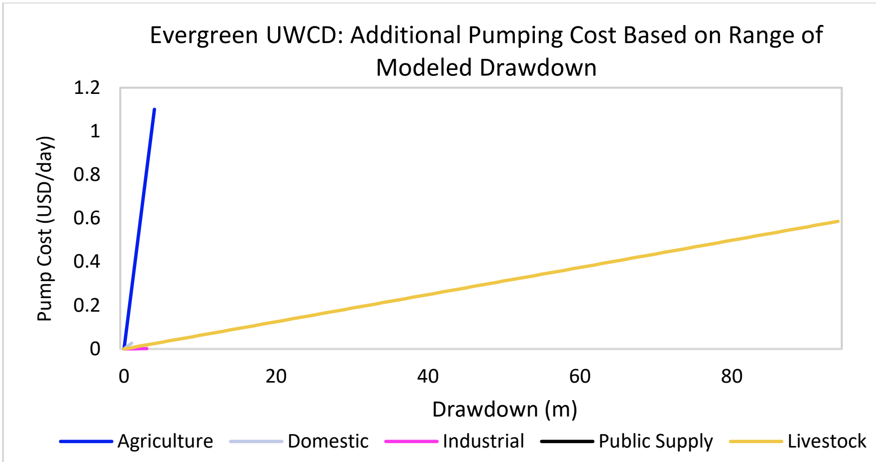


Fig 4-22: Estimated pumping cost curves from drawdown experienced in Evergreen UWCD wells.

4.4.1.2 Gonzales UWCD

Livestock wells were the only sector impacted by transient drawdown in Gonzales UWCD. These wells were found to have experienced a maximum drawdown magnitude of approximately 30 m. Gonzales UWCD experienced drawdown for approximately 425 days, in which drawdown was experienced by only one livestock well in the district. The distribution of transient drawdown that impacted each well sector over the study period is shown in Figure 4-23. The one livestock well in Gonzales UWCD impacted by transient drawdown at some point during the study period made up approximately 14% (1/7) of the sector's well count (Table A-2).

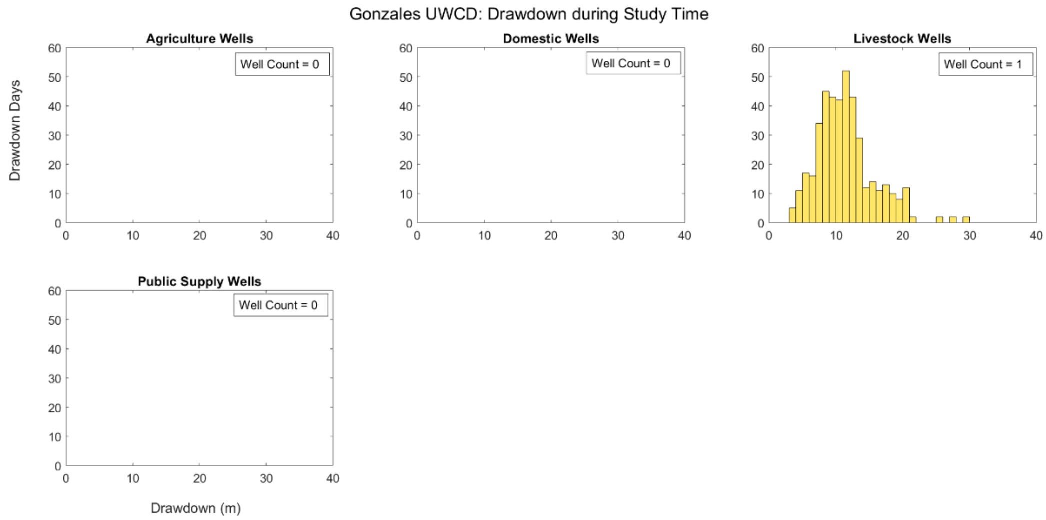


Fig 4-23: Transient drawdown levels experienced over the 8-year study period for Gonzales UWCD sector wells.

The singe livestock well was found to all have experienced a severity of drawdown over impacted days at 4.94%. The greatest 5% of drawdown experienced was at a magnitude of 19.80 m, whereas the median of drawdown magnitude was 10.93 m. As a sector, any livestock well experienced drawdown during 16% (425/2722) of the study period. In this case, this refers to only one affected well out of 7 livestock wells.

Considering daily pumped volumes and electricity cost rates for each sector in Gonzales UWCD, additional pumping costs from transient drawdown over the study time revealed livestock median price of $1.39 per day during days impacted by drawdown (Figure 4-24). At maximum drawdown, livestock well owners paid an additional pumping cost of $3.51 per day. Averaging the cost impacts from transient drawdown over the entire study period, it was determined that the average livestock well owner payed $0.86 more for their groundwater during impacted days, whereas the remaining sectors not impacted by drawdown were unaffected by costs.

Compared to impacted livestock wells in Evergreen UWCD, the drawdown experienced in the livestock well in Gonzales UWCD was greater in both median and top 5% of drawdown. Despite a greater maximum drawdown in Evergreen UWCD livestock wells, drawdown was greater and more sustained over impacted drawdown days for the livestock well in Gonzales UWCD. Examining these costs in proportion to sector GDP revealed average additional pumping during drawdown days to amount to 1.40×10^{-8} % of annual GDP for the livestock well.

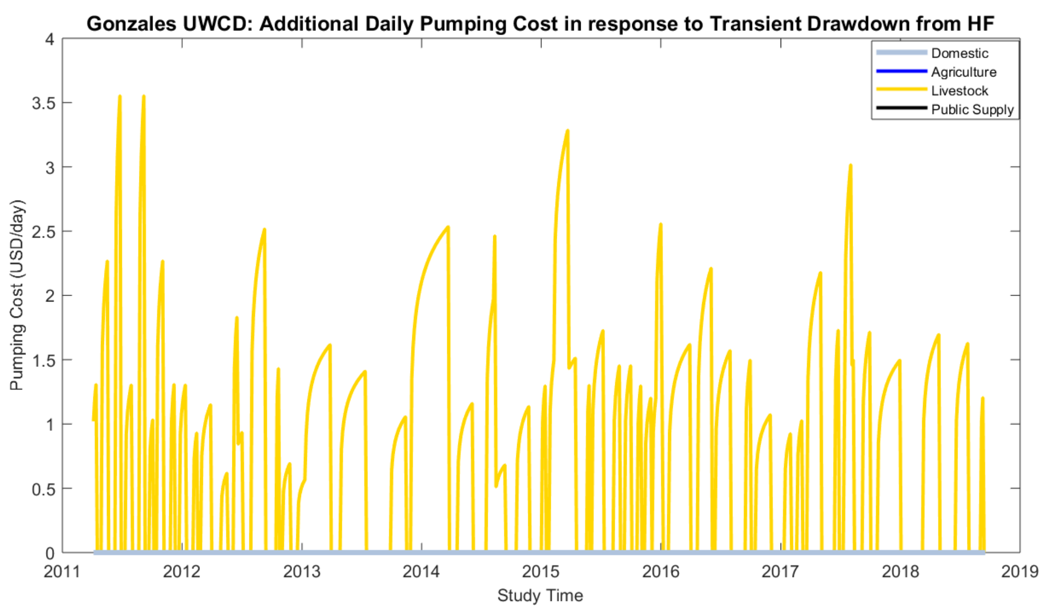


Fig 4-24: Average additional daily pumping cost for wells by sector in Gonzales UWCD over the study period.

Given the magnitude of transient drawdown experienced by sector wells in Gonzales UWCD, pumping cost curves were created using pumping rates and electricity cost rates to estimate pumping costs of drawdown (Figure 4-25) (Table A-3). Given only one well was impacted within the district, only one cost curve was calculated for the impacted livestock well. The livestock well owner impacted was calculated to have paid an additional $0.11 per meter of drawdown, comparatively greater than what impacted livestock well owners paid in Evergreen UWCD. The reason for this disparity was owed to a much greater daily pumping rate for livestock wells in Gonzales UWCD, at 413.58 m^3/day, compared to 23.14 m^3/day in Evergreen UWCD.

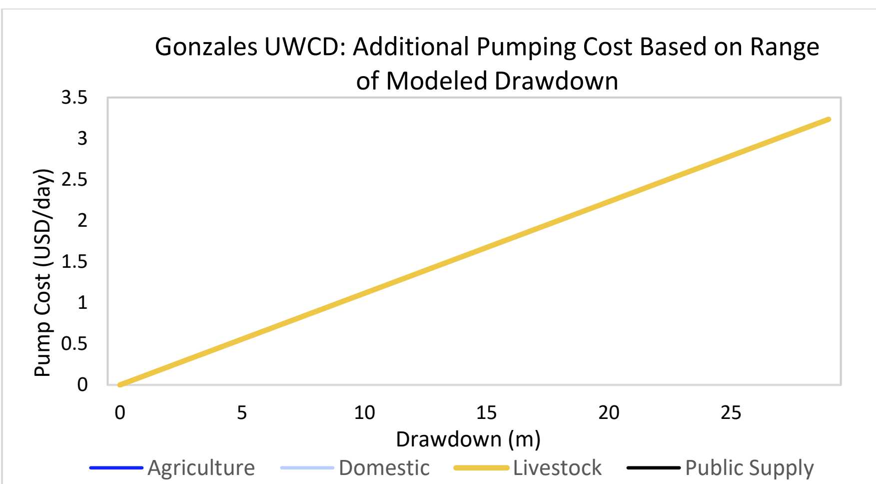


Fig 4-25: Estimated pumping cost curves from drawdown experienced in Gonzales UWCD wells.

4.4.1.3 Live Oak UWCD

Consisting of only 2 well sectors assigned to the Carrizo-Wilcox aquifer system, well impact analysis of drawdown in Live Oak UWCD revealed only livestock wells were impacted by drawdown. The greatest magnitude of drawdown in these wells was approximately 78 m. Over study space and time, Live Oak UWC experienced drawdown for approximately 710 days, spread over 30 impacted livestock wells. The distribution of transient drawdown that impacted this well sector over the study period is shown in Figure 4-26. The count of livestock wells impacted out of the total well count was 91% (30/33) (Table A-2).

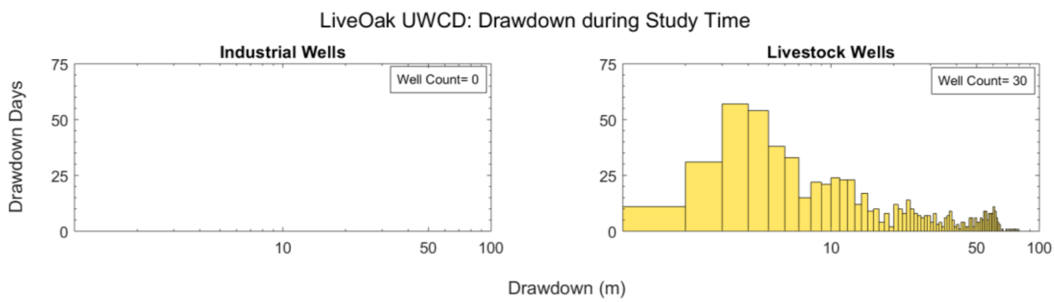


Fig 4-26: Transient drawdown levels experienced over the 8-year study period for Live Oak UWCD sector wells.

Livestock wells were found to have experienced a drawdown severity of 5.07%. This severity was greater than both those of Evergreen and Gonzales UWCD, which revealed livestock wells in Live Oak UWCD experienced more days of impact from the top 5% of drawdown in this sector. The median and 95th percentile of drawdown magnitude was also greaster in Live Oak UWCD, at 12.30 m and 60.45 m. Although livestock wells in Evergreen UWCD experienced a greater maximum drawdown magnitude compared to Live Oak UWCD, a greater top 5% of drawdown magnitude in Live Oak UWCD wells supports the claim of a greater severity of drawdown impacts.

Considering daily pumped volumes and electricity cost rates, the predicted additional pumping costs in Live Oak UWCD over the study period revealed livestock wells paid a price of $0.14 more in groundwater pumping during days impacted by drawdown (Figure 4-27). Additional pumping cost during days of maximum drawdown was found to be approximately $0.57 per day for livestock wells in Live Oak UWCD. Compared to Gonzales UWCD, the cost impacts from maximum drawdown were much less in additional pumping costs, however, they were found to be similar to costs paid in Evergreen UWCD livestock wells. This was owed to both districts having similar daily pumping rates, despite maximum drawdown greater in Evergreen UWCD. Examining these costs in proportion to sector GDP revealed average additional pumping during drawdown days to amount to 1.46×10^{-9} % of annual GDP for livestock wells.

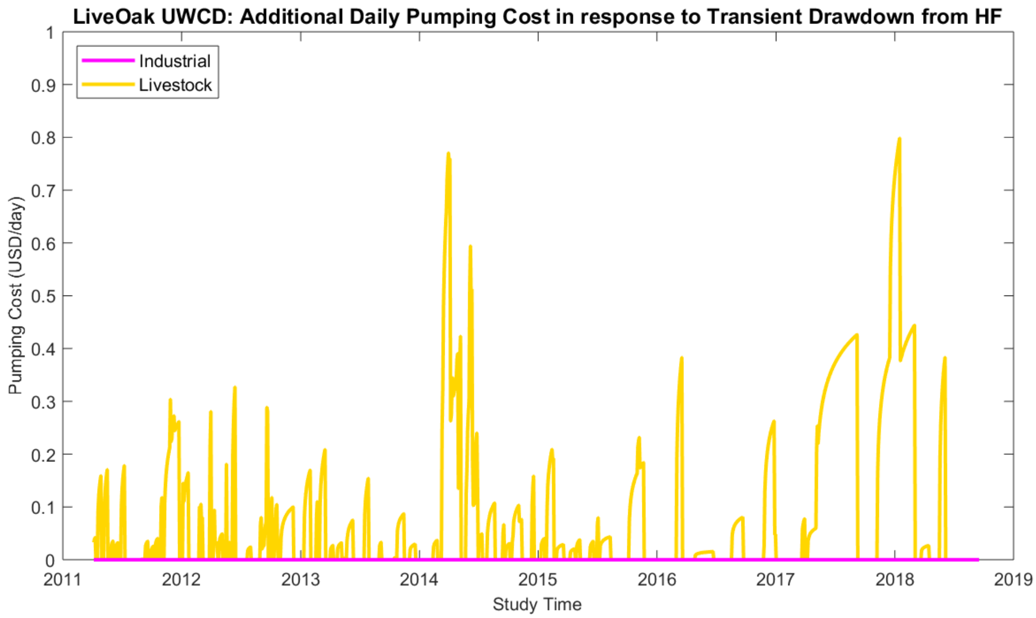


Fig 4-27: Average additional daily pumping cost for sector wells in Live Oak UWCD over the study period.

Additional pumping costs in Live Oak UWCD range from 0 to $0.57 given the range of drawdown, electricity cost rates, and average daily pump rates for the sector (Figure 4-28) (Table A-3). Average daily pumping rates for livestock wells were the second highest out of the other GCDs, behind Gonzales UWCD, which can explain the disparity between the additional costs paid at maximum drawdown. At maximum transient drawdown, additional pumping costs for the livestock sector was $0.57 per day of added drawdown. The average livestock well owner in Live Oak UWCD was estimated to pay $0.01 per m of drawdown, similar to livestock wells in Evergreen UWCD.

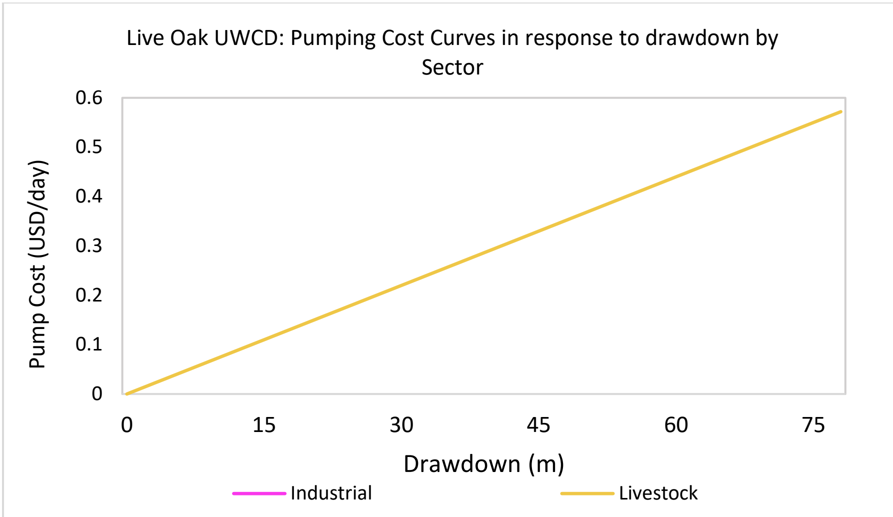


Fig 4-28: Estimated pumping cost curves from drawdown experienced in Live Oak UWCD wells.

4.4.1.4 McMullen GCD

Consistent with previous sections, livestock wells in McMullen GCD experienced the greatest additional drawdown from HF groundwater pumping, at a maximum drawdown magnitude of approximately 200 m, followed by industrial and domestic wells at approximately 70 m, 45 m. Agriculture wells experienced no drawdown impact during the study period. Altogether, 98 wells in McMullen GCD experienced drawdown for approximately 7,435 days, spread over 1 agriculture well, 2 domestic wells, 94 livestock wells, and 1 industrial well. The distribution of transient drawdown that impacted each well sector over the study period is shown in Figure 4-29. Over the 8-year study period, 100% (94/94) of livestock wells were affected by at least one day of drawdown. For the remaining sectors, the percentage of wells impacted in each sector is as follows: 1) 20%

(1/5) agriculture; 2) 33% (2/6) domestic; and 3) 33% (1/3) industrial wells (Table A-2).

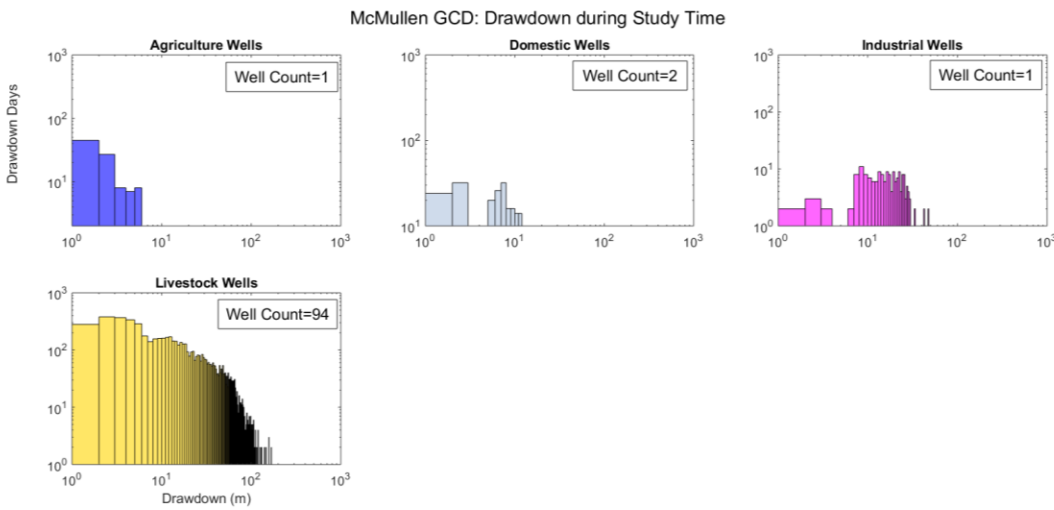


Fig 4-29: Transient drawdown levels experienced over the 8-year study period for McMullen GCD sector wells

Agriculture wells experienced the greatest severity of drawdown within McMullen GCD, at a drawdown magnitude of 5.56 m and greater during 5.08% of drawdown days. Severity for the remaining sectors were 5.07% in domestic wells, 5.00% in livestock wells, and 5.00% in industrial wells, at a drawdown magnitude of 11.74 m, 66.95 m, 41.91 m. These results are similar to those found in Evergreen UWCD. Although the greatest 5% magnitude of drawdown is experienced highest in the single agricultural well during its impacted days, drawdown of 17.70 m and 13.86 m is experienced in over half the impacted days in industrial and livestock wells.

Predicted cost impacts over the study time in McMullen GCD revealed industrial and domestic wells paid an additional pumping price of approximately \$2.74 and \$0.61 per day during days of maximum drawdown over the 8-year period, shown in Figure 4-30. Although livestock wells were previously determined to have experienced the highest magnitude of drawdown, the average pumping rate for the sector is one of the lowest among all GCDs in the region (Table A-1). Therefore, when compared to the average pumping rates of domestic and industrial wells, additional pumping costs were the lowest for livestock wells in McMullen GCD, at approximately \$0.16 during days of maximum drawdown.

The company owning the single industrial well impacted by drawdown was estimated to have paid an additional \$1.00 for groundwater when pumped during days impacted by drawdown. Domestic well owners were estimated to have paid \$0.13 more for their groundwater when pumped during days impacted by drawdown, followed by \$0.01 for livestock well owners. Upon normalizing these costs to sector GDP, the median percent of additional pumping costs during days impacted by drawdown for each sector were found to be $5.28x10^{-10}$ %, $1.23x10^{-10}$ %, and $1.04x10^{-10}$% of annual profits for industrial, domestic, and livestock wells. The absence of agriculture wells in this cost analysis is attributed to a historical reported pump volume of zero for the last decade, despite the existence of agriculture wells within the district.

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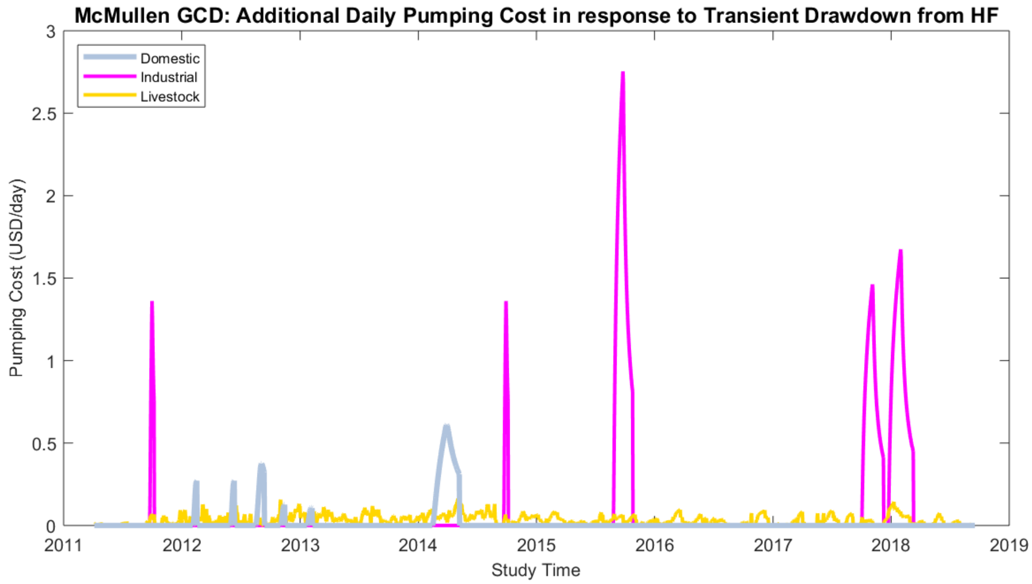

Fig 4-30: Average additional daily pumping cost for sector wells in Live Oak UWCD over the study period.

Considering daily pumped volumes and electricity cost rates in McMullen GCD, pumping cost curves were calculated to estimate the limits of additional pumping costs given maximum transient drawdown within the district (Figure 4-31) (Table A-3). Despite having experienced the greatest magnitude of drawdown over the district, livestock wells are estimated to pay, at most, an additional $0.10 in groundwater pumping, compared to $2.97 for industrial wells and $0.32 for domestic wells. The average industrial well owner in McMullen GCD is calculated to pay an additional $0.06 per m of drawdown, followed by $0.03 for domestic well owners, and less than a cent for livestock well owners.

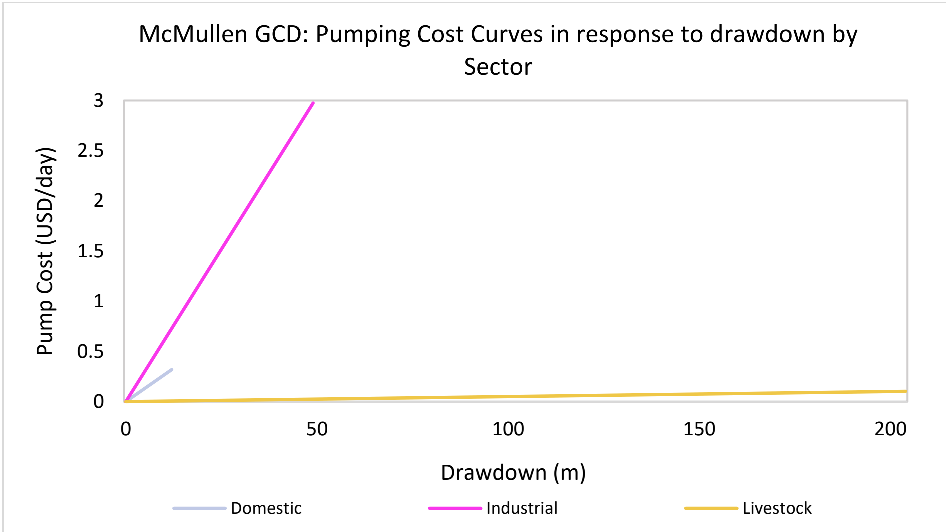

Fig 4-31: Estimated pumping cost curves from drawdown experienced in McMullen GCD wells.

4.4.1.5 Pecan Valley GCD

Consisting of only 2 well sectors assigned to the Carrizo-Wilcox aquifer system, well impact analysis in Pecan Valley GCD revealed livestock wells experienced the greatest additional drawdown from HF groundwater pumping within the district, at approximately 78 m. In the remaining impacted sector, a single industrial well was found to have experienced a maximum drawdown of approximately 5 m during the study period. Altogether, wells in Pecan Valley GCD experienced drawdown for approximately 21,101 days, spread over 175 livestock wells and one industrial well. The distribution of transient drawdown that impacted each well sector over the study period is shown in Figure 4-32. The proportion of impacted wells out of its total sector population revealed 99% (175/177) of livestock wells were impacted within the district, followed by 33% (1/3) of industrial wells (Table A-2).

Livestock wells were found to have experienced the greatest severity in drawdown over its impacted days, at 5.11%, compared to the industrial well at 4.54% severity. This drawdown severity equates to the greatest 5% of drawdown for each well sector at a magnitude of 10.14 m and 4.82 m. The median drawdown experienced by both well sectors was 1.62 m and 0.77 m for the livestock and industrial wells.

Considering daily pumped volumes and electricity cost rates for each sector in Pecan Valley GCD, additional pumping costs in response to transient drawdown over the study time revealed livestock wells paid the greatest additional pumping cost during maximum drawdown days, approximately \$0.28 per day (Figure 4-33). At maximum drawdown, the industrial well was found to have paid an additional pumping cost less than a cent. Although the daily pumping rate of livestock wells throughout each GCD has been comparatively lower than other sectors within each district, the daily pumping rate for livestock wells in Pecan Valley GCD is greater than the rate of the industrial well within the district. Despite a higher pumping rate and greater experienced drawdown, the impacted industrial well paid less than a cent in additional pumping per m of drawdown. In contrast, the average livestock well owner had paid \$0.01 more for groundwater per m of drawdown. Examining these costs in proportion to sector GDP revealed the median additional pumping during drawdown days to amount to $1.01\text{x}10^{-10}$% for livestock (Figure 4-44). Proportional cost of additional drawdown pumping to GDP was found to be minimal for the impacted industrial well.

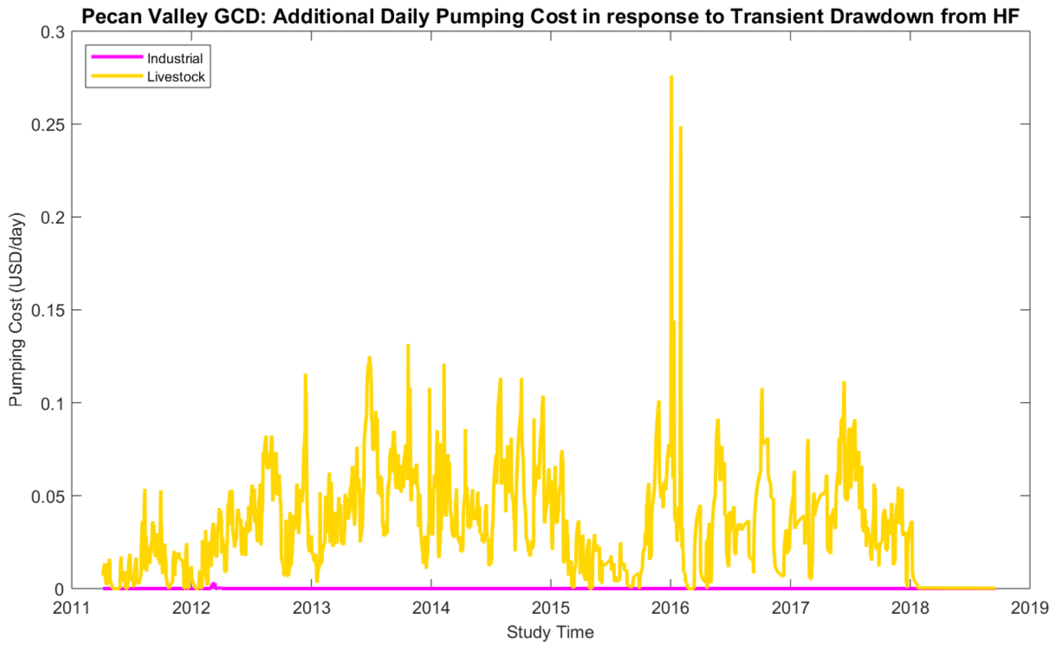

Fig 4-33: Average additional daily pumping cost for sector wells in Pecan Valley GCD over the study period.

Considering daily pumped volumes and electricity cost rates for each sector in Pecan Valley GCD, predicted costs over the study time revealed minimal impacts compared to the additional costs paid by the former GCDs (Figure 4-34). The average livestock well owner paid less than a cent per m of drawdown. Similarly, the single industrial well paid even less than that per m of drawdown. Maximum pumping costs reached upwards to $0.28 per day for livestock well owners during times of maximum drawdown, despite modeled drawdown of 78 m (Table A-3). The low additional pumping cost to the industrial well during times of maximum drawdown was owed to both minimal daily pumping rates for that sector and a relatively low magnitude of maximum drawdown experienced in the well, compared to the livestock well.

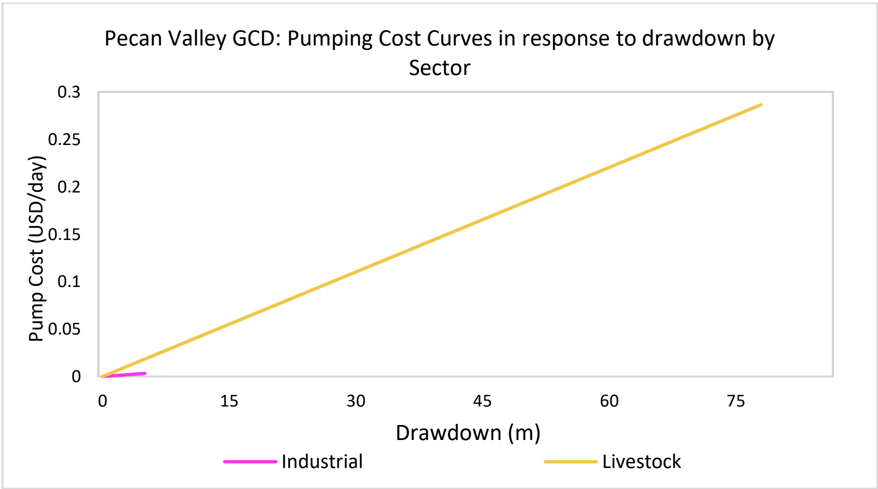

Fig 4-34: Estimated pumping cost curves from drawdown experienced in Pecan Valley GCD wells.

4.4.1.6 Wintergarden GCD

Well impact analysis in drawdown in Wintergarden GCD revealed the greatest magnitude of transient drawdown reached 320 m. All livestock wells were impacted for at least one drawdown day during the study period. Maximum drawdown in livestock wells was followed by maximum drawdown magnitudes of 29 m, 17 m, 11 m, and 7 m in agriculture wells, domestic wells, industrial wells, and public supply wells, respectively. Altogether, 381 wells in Wintergarden GCD experienced drawdown for approximately 26,000 days. These include 11 agriculture wells, 14 domestic, 347 livestock, 6 industrial, and 3 public supply wells. The percentage of wells from each sector affected by drawdown in the district are as follows: 1) 50% (3/6) public supply; 2) 21% (14/68) domestic; 3) 25% (6/24) industrial; and 4) 14% (11/77) agriculture wells (Table A-2). The distribution of transient drawdown that impacted each well sector over the study period is shown in Figure 4-35.

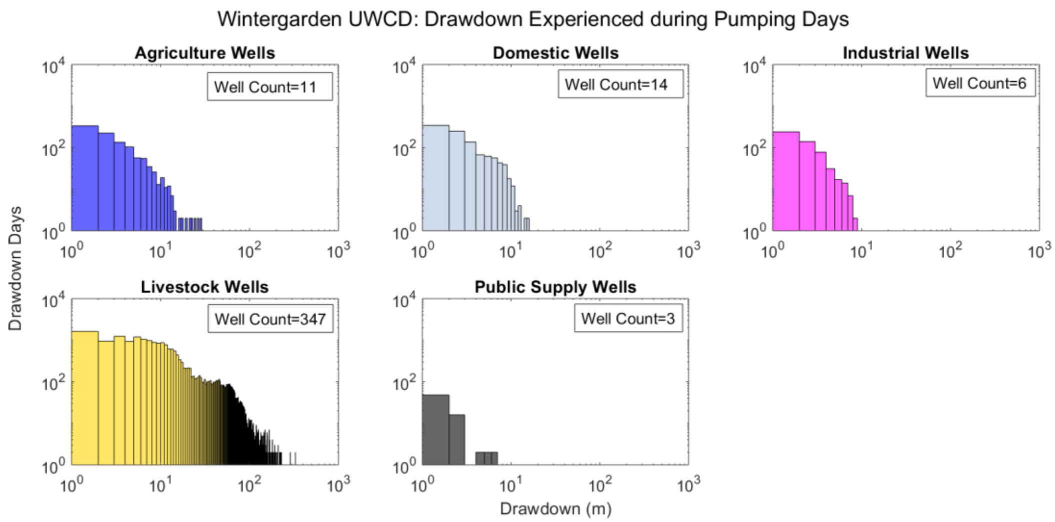

Fig 4-35: Transient drawdown levels experienced over the 8-year study period for Wintergarden GCD sector wells.

Transient drawdown distribution normalized to the number of drawdown days experienced for each well type revealed agriculture, domestic, and industrial wells experienced the greatest severity in drawdown, at 5.04%, 5.03%, and 5.03%. Severity in these wells equated the greatest 5% of drawdown magnitude at 10.71 m, 8.38 m, and 5.26 m. The remaining wells experienced severities of 5.00% in livestock wells and 4.72% in public supply wells. Despite having experienced one of the lowest severities in drawdown, the greatest 5% magnitude of drawdown experienced in livestock wells was the greatest compared to the other sectors, at a magnitude of 68 m.

Predicted cost impacts over the study time in Wintergarden GCD revealed agriculture wells paid the greatest in additional pumping costs during days of maximum drawdown, approximately \$10.74 per day (Figure 4-36). Additional pumping cost for the remaining sectors were \$7.32, \$1.39, \$0.86 for public supply, livestock, and industrial wells during days of maximum drawdown impact. Averaging the cost impacts from transient drawdown over the entire study period, the median additional cost a public supply well owner paid for their groundwater during days impacted by drawdown was \$1.42, whereas agriculture well owners paid \$1.37. Industrial, domestic, and livestock well owners paid on average an additional cost of \$0.15, \$0.07, \$0.03.

Normalizing additional costs by sector GDP, median additional pumping costs during drawdown days amounted to 1.38×10^{-8}% of annual profits made in agricultural operations, followed by public supply utilities, at 4.28×10^{-9}% of annual profits during days of drawdown. Median drawdown for livestock well owners resulted in additional pumping costs in response to drawdown made up only 3.33×10^{-10}% of annual profits. This is despite livestock wells having experienced the greatest magnitude in drawdown, compared to other sector wells in Wintergarden GCD. The remaining domestic and industrial wells experienced median additional pumping costs of 7.04×10^{-11}% and 8.04×10^{-11}% of annual GDP during days of drawdown.

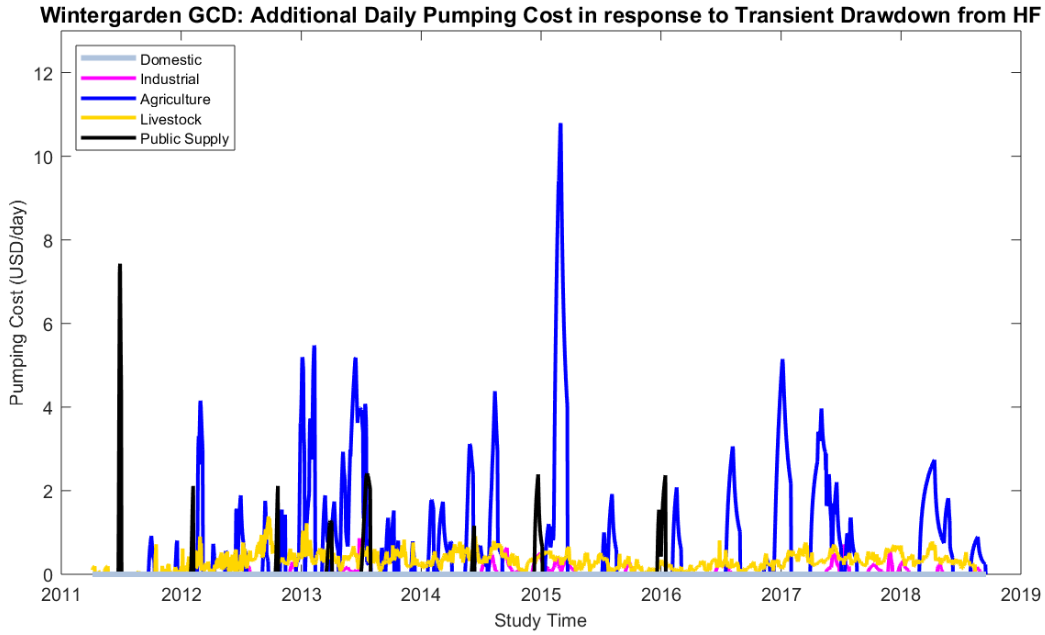

Fig 4-36: Average additional daily pumping cost for sector wells in Live Oak UWCD over the study period.

Given the magnitude of transient drawdown experienced by sector wells in Wintergarden GCD, pumping cost curves were created for each sector based on daily pumped volumes and electricity cost rates (Figure 4-37) (Table A-3). The greatest additional pumping costs paid by a well for each sector at maximum drawdown are as follows: 1) $11.36 per day for agriculture wells; 2) $8.20 per day for public supply wells; 3) $0.90 per day for industrial wells; 4) $0.63 per day for livestock wells; and 5) $0.42 per day for domestic wells. Despite livestock wells having experienced the greatest magnitude of drawdown from HF, agriculture wells experienced the greatest additional pumping cost with added drawdown, at $11.36 during maximum drawdown. However, public supply wells were estimated to have had the greatest pumping cost gradient with added drawdown, at an additional $1.17 per meter of drawdown. Therefore, the maximum possible cost impact for public supply wells were limited by transient drawdown magnitude, but are at risk of increasing due to its elevated drawdown severity, in comparison to the other sectors in Wintergarden GCD. The average agricultural well owner was calculated to have paid an addition $0.41 per m of drawdown during impacted days, followed by $0.08 and $0.03 for industrial and domestic wells. The additional cost of pumping per meter of drawdown is negligible for livestock wells given their daily pump rates.

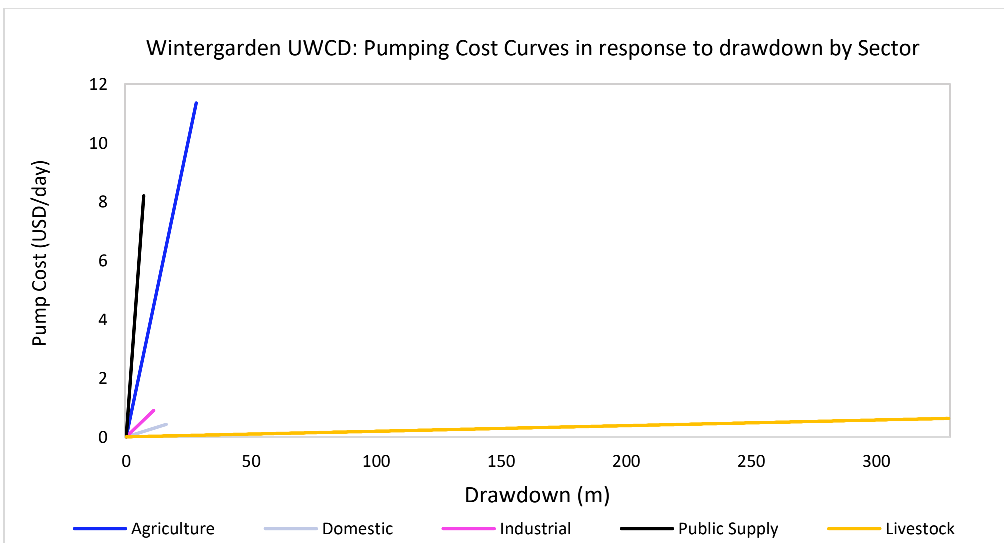

Fig 4-37: Estimated pumping cost curves from drawdown experienced in Wintergarden GCD wells.

5. DISCUSSION

5.1 Drawdown Model Comparison

For the purpose of modeling fluctuating groundwater demands of the oil and gas industry, implementing an annualized drawdown method to model drawdown from HF groundwater pumping did not supply adequate temporal or spatial resolution over the EF study area and time. Instead, a transient drawdown modeling approach was required. In the procedure of annualizing HF pumping events, the magnitude of drawdown was underestimated compared to predicted drawdown in the transient model. The difference in maximum predicted drawdown between the two methods reached 97.7%. Despite this dampening, the annualized method distributed drawdown too broadly across the GCD, resulting in over-estimated impacted stakeholders.

The greatest total cost to a stakeholder was estimated to be $190 to a single livestock well in Gonzales UWCD over the 8-years of HF pumping. The next greatest cost was approximately $90 to a single agriculture well owner in Wintergarden GCD over the 8-year period. Total median and top 5% costs to stakeholders were estimated to be approximately $60 and $190. Given these total estimated additional pumping costs were spread over the period of 8-years, it can be inferred that these costs resulted in diminutive economic impacts to aquifer stakeholders in other sectors.

The greatest areal extent of land types impacted by underlying annual drawdown were almost entirely ‘Barren/Shrubland’ and ‘Pasture/Hay’ for all the years in every GCD. These results are supported by findings in the transient model which revealed livestock wells experienced the greatest impact from HF pumping. This impact is both the greatest magnitude in drawdown and the greatest percentage of impacted wells within a sector compared to other sectors in the district.

Although only consistent for one GCD, drawdown severity for wells in Pecan Valley GCD were greatest for livestock, domestic, and public supply wells. These findings agreed with the land types impacted by annual drawdown, which revealed that drawdown of atleast 0.5 m occurred in over 70% and 72% of the districts developed land and designated ‘Pasture/Hay’ land, respectively. Therefore, the disignated land use types in Pecan Valley GCD may be used as an adequate indicator to define potential impact to stakeholders from groundwater drawdown caused by HF.

Interference between HF pumping wells was not addressed by the transient model as it was in the annualized drawdown model. In general, overlapping drawdown from transient pumping wells for HF was experienced infrequently over the EF, however, results from the transient models were able to identify local areas in certain GCDs with a high occurrence of overlap. Therefore, further study is needed to improve the transient model to calculate combined drawdown from neighboring drawdown cones from rig/frack supply wells in these areas. Additionally, because the tranisent method was focused on pumping from wells in both the Carrizo-Wilcox aquifer system and wells that were defined as 'deeper' or outside of the model boundaries, further study is required to differentiate which wells were pumping from brackish groundwater sources. The TWDB BRACS database is the best suited resource to accomplish this next step (TWDB-BRACS, 2019).

If the priority of a study is to capture drawdown interference between adjacent wells pumping over long periods of time, the annual drawdown model is an acceptable method. The key condition for its application, however, is the assumption of constant pumping rates. Therefore, considering the substantial discrepencies between the two methods when HF pumping is modeled, it can be inferred that simply annualizing an intense pumping event over long periods of time will not produce the same results as the transient method.

To attain more detailed impacts from drawdown induced by HF pumping, the transient drawdown method was more efficient as it quantified time-dependent groundwater drawdown and the additional pumping cost incurred by individual stakeholders and sectors. Using trends in drawdown severity for each district, groundwater competition can be characterized into two behaiviors, chronic and time-dependent. Therefore, total additional pumping costs were found to have an added component dependent on the type of competition a well sector predominantly experienced. Transient drawdown results from this model estimated an individual's greatest additional pumping costs of groundwater in response to drawdown in their well caused by nearby pumping for HF. Whereas average drawdown tends to appear minimal over if pumping rates are averaged over a long time frame, the use of actual pumping rates over the actual days pumped allowed drawdown and costs to be captured at the local scale.

5.2 Groundwater Competition

Impacts from transient drawdown on sector wells revealed groundwater competition in the Carrizo-Wilcox aquifer system occurred in certain wells chronically throughout the study period, and in other wells over short, but intense periods. Chronic drawdown impacts were observed in all livestock wells for every GCD. Although severity was a useful index to define highly impacted wells within a region in respect to its impacted days, it was found to greatly under-value chronic drawdown in districts that experienced both chronic and ephemeral competition during the study time. This was evident in Evergreen UWCD, McMullen GCD, Pecan Valley GCD, and Wintergarden GCD. In these districts, although livestock wells experienced greater drawdown over more drawdown days, the remaining sectors experienced greater drawdown severities. The reason for greater drawdown severity was owed to a greater number of drawdown days that experienced a drawdown magnitude in the 95th percentile and greater for that sector in the given GCD. Additionally, for wells with lower counts and drawdown days, a high severity could be driven by disproportionate well spacing to rig/frack supply wells in just a small number of sector wells. These results are consistent given the average duration of a HF treatment is 8 days, therefore, chronic groundwater competition observed livestock wells during the study time was an unexpected finding.

The greatest chronic groundwater competition in Wintergarden GCD was experienced by well owners in the livestock industry, which occurred in 100% of wells. The top 5% and maximum drawdown magnitude in these wells was the greatest compared to the other GCDs, at 68.33 and 328.56 m. Although these livestock wells experienced consistently greater drawdown during days of impact from HF pumping, these drawdown days account for a total of 1201 days out of the 2722 days of the study period, approximately 44%. Groundwater competition in the remaining in livestock wells are characterized as follows: 1) 100% impact during 36% of study period in McMullen GCD; 2) 99% impact during 44% of study period in Pecan Valley GCD; 3) 94% impact during 42% of study period in Evergreen GCD; 4) 91% impact during 11% of study period in Live Oak UWCD; and 5) 14% impact during 8% of the study period in Gonzales UWCD.

In GCDs where ephemeral groundwater competition occurred alongside chronic competition, the agricultural sector was impacted the greatest. The impact on these wells were the greatest in the following GCDs: 1) Evergreen GCD, with 0.5% (1/198) of agriculture wells impacted during 0.6% study period; 2) McMullen GCD, with 20% (1/5) agriculture wells impacted during 4.3% of study period; and 3) Wintergarden GCD, with 14.5% (11/76) of agriculture wells impacted during 17.9% of the study period.

5.3 Cost Impacts to Stakeholders

Utilizing the transient drawdown method, the additional cost paid by each sector to pump groundwater during days of drawdown was calculated for every well over the EF region (Table A-4). The total cost reported represents the stakeholders impacted by the greatest 5% of transient drawdown, compared to the median of transient drawdown. Over the 8-year study period of modeled transient drawdown from HF pumping, the greatest 5% of drawdown resulted in an estimated maximum additional pumping cost of approximately $200, paid by 1 industrial well owner in McMullen GCD. The highest estimated cost paid by stakeholders in the remaining GCDs are summarized as follows: approximately 1) $190 in Gonzales UWCD, paid by one livestock well owner; 2) $90 in Wintergarden GCD, paid by one agriculture well owner; 3) $15 in Evergreen GCD, paid by 13 livestock well owners; 4) $20 in Live Oak, paid by two livestock well owners; and 5) $3 in Pecan Valley GCD, paid by 9 livestock well owners.

The impacts of HF groundwater pumping on additional pumping costs to local stakeholders was revealed to be widely variable across GCDs and stakeholder sectors. Although the livestock industry experienced consistently higher magnitudes of drawdown in their impacted wells than wells in other sectors, the total cost impacts to livestock wells were greatest only in Gonzales UWCD, Live Oak UWCD, and Evergreen UWCD. This was attributed to chronic drawdown and a higher pumping rate for livestock wells, compared to those within and outside the district.

The greatest cost impacts from the top 5% of transient drawdown revealed that of the majority of sectors impacted by the highest additional pumping costs, impacts were frequently only experienced by one well. This occurs consistently in agriculture wells and public supply wells. The cost impact from the median transient drawdown results in an additional cost of less than a cent for almost all drawdown impacted sectors but the livestock industry. The median price livestock well owners paid over the 8-years of HF pumping are as follows: approximately 1) \$3 in Evergreen UWCD for 248 well owners; 2) \$0.15 in Live Oak UWCD for 28 well owners; 4) \$0.55 in McMullen GCD for 89 well owners; 5) \$1 in Pecan Valley GCD for 166 well owners; and 6) \$1 in Wintergarden GCD for 5 well owners.

The overall cost impacts from groundwater drawdown caused by nearby pumping to supply HF operations are considered minimal when compared to average GDP for each sector. For the wells impacted by the greatest additional price of pumping during the study period, the cost of additional pumping accounted for 1.89×10^{-6}% of annual GPD for the livestock well in Gonzales UWCD, followed by 9.18×10^{-7}% for the agriculture well in Wintergarden GCD, 2.8×10^{-7}% for the 9 livestock wells in Pecan Valley GCD, 2.15×10^{-7}% for the 2 livestock wells in Live Oak UWCD, 1.5×10^{-7}% for the 14 livestock wells in Evergreen GCD, and 1.07×10^{-7}% for the industrial well in McMullen GCD.

Although the additional price of pumping was low, the indirect costs associated with unavailable groundwater, pump failure, or deepening a well, can run into the tens of thousands of dollars. Unfortunately, assessing when this occurred was beyond the scope of this study. Several owners of the livestock wells that experienced greater than 68 m in drawdown, for example, could be expected to have suffered costs from burned out pumps or additional cost of deepening their well. Furthermore, the database used to report the locations of all sector wells is incomplete. Even GCD general managers who constantly work with aquifer stake holders do not know the locations of all wells, especially those for private household or irrigation use (Obkirchner, 2018). Therefore, more primary data collection in the field is required to quantify the cost to different sectors more accurately. This study succeeded in identifying key sectors and regions where groundwater competition from intensive, but ephemeral pumping for HF supply in the EF, was most extreme. Future work may build on this approach with the collection of primary field data from well owners in the vicinity of the most extreme drawdown magnitudes identified in this thesis study.

5.4 Uncertainties and Biases in the Transient Drawdown Modeling Approach

Despite seemingly exact drawdown and cost estimations made in this thesis, numerous assumptions were made regarding oil & gas activities, well owners, and the accuracy and completeness of data contained in databases. Table 5-1 summarizes the assumptions made in response to the uncertainties identified throughout this study. This is followed by how the assumption would potentially skew modeled drawdown and cost impact results.

Table 5-1: Study assumptions paired with resulting influences on final drawdown and cost estimations.

Assumption	Over/Under Estimate Competition	Result
Wells reported in the SDR database were exhaustive, leaving no well unaccounted for.	**Under estimate**	Drawdown and cost impacts to wells were overestimated.
Transient drawdown remained within the extents of each modeled local grid.		
HF water use was sourced from 100% groundwater.	**Over estimate**	Drawdown and cost impacts to wells were overestimated.
Sector wells were present from April 5, 2011 to September 17, 2018.		
Drawdown from HF pumping was experienced throughout the Carrizo-Wilcox aquifer system, disregarding isolated formations.		
All HF groundwater was sourced from officially designated rig/frack supply wells.	**Both**	Depending on the intensity of the HF events and local distribution of sector wells surrounding, drawdown and cost impacts were both overestimated and underestimated.

6. CONCLUSIONS

6.1 Summary

This investigation estimated the aquifers used to supply water for HF operations in the EF and incorporated methods to spatially correlate HF events from FracFocus to rig/frack supply wells from the SDR database. Two drawdown modeling techniques were utilized in this study. One was used to estimate land type areas impacted using the annualized drawdown approach, and the other estimated additional pumping costs to owners of wells in other sectors in response to time dependent drawdown from ephemeral, but intensive pumping from rig/frack supply wells. Results from both modeling techniques vary in modeled drawdown but agree qualitatively. For example, annualized drawdown consistently indicated that the aquifer underlying the most impacted land type would be used for livestock grazing. The transient drawdown model concurred that the greatest drawdown and additional pumping costs would be paid by owners of livestock wells.

Maximum modeled drawdown across all 6 GCDs exceeded 300 m, whereas the annualized model predicted a maximum drawdown of only 8 m. This emphasizes the need for higher resolution studies at a local scale. The additional pumping costs in response to drawdown impacted wells varied depending on sector and GCD location. Over the length of the 8-years, the maximum cost paid by individual stakeholders ranged from fractions of a cent to approximately $200 for the entire study period. Additionally, pumping price curves were created for every GCD sector incorporating factors such as electricity rate, pumping rate, and magnitude of drawdown. Variables such as electricity cost rates for each industry type, magnitude of drawdown, and historic groundwater use for each sector were used to calculate GCD-specific pumping price curves per meter of drawdown experienced within the GCD. For wells in sectors with a high daily pumping rate, the additional costs were found to be much greater than the costs imposed on wells with lower pumping rates. Therefore, public supply and agriculture wells incurred greater additional pumping expenses for electricity than livestock and domestic wells. This discrepancy not only reveals that high drawdown impact does not necessarily result in high additional electricity costs, but also shows that minimal drawdown may result in higher pumping costs. Results from this study offer new insights into systematic approaches for quantifying the price of groundwater, with this approach addressing the added cost impact when groundwater level is affected by drawdown from HF.

This analysis of the additional cost of pumping from a well with lower water levels does not address the possibility that some well owners suffered the expense of replacing a damaged pumps when the water level dropped below it briefly from pumping for HF supply. Future work should systematically investigate the standing water height above the intake points for pumps across all sectors to assess this risk.

6.2 Implications to Texas Groundwater Planning & Management

Needs and objectives in water planning and management are dynamic over time. New issues arise as industries change or are created. Regarding HF, while not a new practice, its application is becoming more widespread, posing unique challenges associated with a new, geographically widespread industry which pumps groundwater in an intensive, localized, but ephemeral way. Although HF is a seemingly small amount of water used at the state scale, its consumption of 16% of the region's total water use has posed challenges that are not currently addressed by the 2017 State Water Plan (Texas, 2017).

Time dependent water availability has already impacted stakeholders throughout the EF region, in which this study modeled and quantified the monetary impacts, however, these intermittent shortages are still unaccounted for in state water planning to improve future management. As GAM models consider yearly availability, the current 50-year planning window in anticipation of record drought should also be accompanied by more fine-time-scale planning to evaluate the risk of ephemeral drawdown for HF pumping. Given the volatile nature of the oil and gas industry, this kind of planning can be nearly impossible, but should be taken as an opportunity to approach the issues from a new angle. The results from this study offer a systematic method to quantify additional pumping costs in wells affected by drawdown, and can offer a new method in both planning and litigation.

6.3 Interdisciplinary Applications

One of the original goals of this study was to develop a simplified groundwater drawdown model that could be easily understood by professionals with various backgrounds and intentions. This goal was achieved by utilizing publicly available data made possible by diligent data collection and upkeep by the TWDB and state mandates requiring oil and gas companies to report HF water contribute to the FracFocus public database. It should not be overlooked that these two public databases, combined with the well-characterized regional geology provided by the GAMs, provided all the critical data needed to assess groundwater competition in a transparent way.

The model developed for this thesis can be applied to a number of situations to quantify groundwater competition from distributed pumping across any region. The software Matlab™ was used to model and process transient drawdown results, however, such a model could easily be created in any open-source software by following the semantics of the code provided in the appendix. A single groundwater flow equation, Theis (1935), was utilized to model groundwater drawdown in response to well pumping.

The other goal of this project was to approach the 'Water-for Energy' nexus in the EF shale from the perspective of groundwater conservation, while being responsive to public needs. Identifying these needs and data gaps were predominantly accomplished through community involvement and personally reaching out to aquifer stakeholders overlying the EF. Upon weighing the many different opinions, conflict often arose from current laws that require very mobile groundwater to be managed as static plots belonging to private land-owners. While this study offers no alternative methods for managing groundwater, a model that easily conveys drawdown and transfers impacts as a dollar price is a valuable application of the scientific method to reveal the winners and losers in the ongoing exploitation of aquifers.

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APPENDIX

Table A-1: Pump rate estimates used in the pump cost calculation, $C = \frac{0.746Qhc}{3960\mu_p\mu_m}$, defined in Ch.3 Section 3.2

TWDB Historical Water Survey	Agriculture		Daily Pump Rate	Domestic		Daily Pump Rate	Livestock		Daily Pump Rate	Industrial		Daily Pump Rate	Public Supply		Daily Pump Rate
Evergreen UWCD	Total Volume (m^3)	99,162,188	1,021.34	Total Volume (m3)	-	50.00	Total Volume (m3)	2,956,300	23.14	Total Volume (m3)	116,098	1.99	Total Volume (m3)	16,480,527	1,736.62
	Well Count	266		Well Count	1,452		Well Count	350		Well Count	160		Well Count	26	
Gonzales UWCD	Total Volume (m^3)	2,772,863	584.38	Total Volume (m3)	-	50.00	Total Volume (m3)	9,057,444	413.58	Total Volume (m3)	1,095,727	37.52	Total Volume (m3)	3,225,550	420.82
	Well Count	13		Well Count	570		Well Count	60		Well Count	80		Well Count	21	
Live Oak UWCD	Total Volume (m^3)	-	-	Total Volume (m3)	-	50.00	Total Volume (m3)	566,167	27.21	Total Volume (m3)	1,168,000	91.43	Total Volume (m3)	-	-
	Well Count	-		Well Count	53		Well Count	57		Well Count	35		Well Count	-	
McMullen GCD	Total Volume (m^3)	-	-	Total Volume (m3)	-	50.00	Total Volume (m3)	69,075	1.87	Total Volume (m3)	246,696	225.29	Total Volume (m3)	-	-
	Well Count	6		Well Count	23		Well Count	101		Well Count	3		Well Count	-	
Pecan Valley GCD	Total Volume (m^3)	405	0.06	Total Volume (m3)	-	50.00	Total Volume (m3)	1,134,000	13.63	Total Volume (m3)	199,824	2.41	Total Volume (m3)	3,667,136	1,674.49
	Well Count	20		Well Count	916		Well Count	228		Well Count	227		Well Count	6	
Wintergarden GCD	Total Volume (m^3)	47,263,253	1,505.68	Total Volume (m3)	-	50.00	Total Volume (m3)	918,942	7.09	Total Volume (m3)	5,327,400	304.08	Total Volume (m3)	7,583,435	2,968.08
	Well Count	86		Well Count	295		Well Count	355		Well Count	48		Well Count	7	

Table A-2: Count of sector wells impacted by transient drawdown out of total wells and the average number of days each sector experienced modeled drawdown.

Transient Model: Sector Well Count Impacted by Drawdown During Total Time						
		Agriculture	Domestic	Industrial	Livestock	Public Supply
Evergreen UWCD	# Wells Affected/Well Count	1/198	1/398	2/19	261/276	0/19
	Days Affected/Total Time	17/2722	4/2722	10/2722	1143/2722	0/2722
Gonzales UWCD	# Wells Affected/Well Count	0/4	0/153	-	1/7	0/19
	Days Affected/Total Time	0/2722	0/2722	-	213/2722	0/2722
Live Oak UWCD	# Wells Affected/Well Count	-	-	0/4	30/33	-
	Days Affected/Total Time	-	-	0/2722	297/2722	-
McMullen GCD	# Wells Affected/Well Count	1/5	2/6	1/3	94/94	-
	Days Affected/Total Time	59/2722	69/2722	93/2722	991/2722	-
Pecan Valley GCD	# Wells Affected/Well Count	-	-	1/1	175/177	-
	Days Affected/Total Time	-	-	11/2722	1209/2722	-
Wintergarden GCD	# Wells Affected/Well Count	11/76	14/68	6/24	347/347	3/6
	Days Affected/Total Time	486/2722	495/2722	313/2722	1201/2722	64/2722

Table A-3: Maximum drawdown experienced by sector wells from the transient drawdown model. Used to calculate local pumping rate per meter of drawdown.

Transient Model: Maximum Drawdown at Sector Wells over total study and space (meters)						
	Evergreen UWCD	Gonzales UWCD	Live Oak UWCD	McMullen GCD	Pecan Valley GCD	Wintergarden GCD
Agriculture wells	3.72	0.00	-	6.14	-	28.50
Domestic wells	0.01	0.00	-	12.33	-	16.48
Industrial wells	2.53	-	0.00	48.59	4.87	11.29
Livestock wells	94.45	29.35	78.31	204.00	78.35	328.56
Public supply wells	0.00	0.00	-	-	-	6.79

Table A-4: Summary of the total costs paid by stakeholders impacted using the transient model.

Total Additional Pumping Cost Paid by Stakeholders over 8-years of HF in the EF		Agriculture		Domestic		Industrial		Livestock		Public Supply	
	Percentile	Cost (USD)	Stakeholder Count	Cost (USD)	Stakeholder Count	Cost (USD)	Stakeholder Count	Cost (USD)	Stakeholder Count	Cost (USD)	Stakeholder Count
Evergreen UWCD	50th	0	0	0	0	0	1	2.86	248	0	0
	95th	0	1	0.01	1	2.53	1	14.95	13	0	0
Gonzales	50th	0	0	0	0	-	-	63.84	0	0	0
	95th	0	0	0	0	-	-	188.87	1	0	0
Live Oak UWCD	50th			-	-	0	0	0.15	28		
	95th			-	-	0	0	21.41	2		
McMullen	50th			0	1	0	0	0.55	89		
	95th			17.92	1	202.52	1	2.14	5		
Pecan Valley GCD	50th	-	-	-	-	0	0	0.96	166	-	-
	95th	-	-	-	-	0.03	1	2.81	9	-	-
Wintergarden	50th	0	10	0	13	0	330	0.84	5	0	2
	95th	91.35	1	7.57	1	29.93	17	8.04	1	77.06	1

Code A-1: This is the first step in MATLAB after rig/frack supply wells were spatially correlated to HF events from FracFocus database. This reorganized the data to create individual pumping tests for all rig/frack supply wells.

```
% This file reads in the pumping schedule for fracking operations

% just reads in the numerical values in the excel sheet
mat=xlsread('C:\Users\USER\Documents\MATLAB\PumpSchedule\Matlab_pump_schedule.xlsx
');

% reads in the entire excel sheet including column labels
[~,~,ID_table]=xlsread('C:\Users\USER\Documents\MATLAB\PumpSchedule\Matlab_pump_sc
hedule.xlsx');

mat(:,5)=mat(:,5)+693960; % converts from excel to matlab date format
mat(:,6)=mat(:,6)+693960; % does it again
mat(:,7)=mat(:,6)-mat(:,5)+1; % calculates number of days the well is kept on for
to supply water for a single fracking operation

to=min(mat(:,5)); % start date of pumping for fracking for all wells
tend=max(mat(:,6)); % final date of pumping for fracking for all wells

C = unique(mat(:,4)); % creates a vector of unique well IDs

hold on
for i=1:length(C)
    Ind = find(mat(:,4)==C(i)); % creates an index vector of ones in all the
places where the "ith" well ID occurs
    wellmat=zeros((tend-to+1),2); % allocates space in a matrix to store all days
and all pumping rates for days well was pumped
    wellmat(:,1)=to:tend; % fill in first column with dates running from start to
finish of all pumping for all wells
        for j=1:length(Ind)
            startdate=mat(Ind(j),5); % stores start date for current pumping event
"j" for current well "i"
```

```
            enddate=mat(Ind(j),6); % stores stop date
            startrow=find(wellmat(:,1)==startdate); % finds the start row in
"wellmat" when pumping turns on for the "jth" pumping event for the "ith" well
            endrow=find(wellmat(:,1)==enddate); % blah
            V=mat(Ind(j),9); % total volume of water used for frack job from "jth"
pumping event (m3)
            Q=V/(enddate-startdate+1); % m3/day
            wellmat(startrow:endrow,2)=wellmat(startrow:endrow,2)+Q; % enters the
average pumping rate for that pumping event in m3/day
        end

        a=plot(wellmat(:,1),wellmat(:,2)); % plots pumping rate over all time
        xlabel('Time');
        ylabel('Pumping Rate, Q (m^{3}/day)');
        datetick('x',10)
        title('Pump Schedule')

         %ID=num2str(C(i)); % gets ID of current "ith" well

%path=['C:\Users\USER\Documents\MATLAB\PumpSchedule\Wells_Pump_Schedule\Wells_Hydr
ographs' ID];
         %saveas(a,path,'jpeg');

        %path=['C:\Users\USER\Documents\MATLAB\PumpSchedule\Wells_Pump_Schedule\'
ID];
        %xlswrite(path,wellmat)
end
 hold off
```

Code A-2: Theis drawdown and recovery Matlab code used to model many wells over a large area.

```
 % This script predicts the drawdown cone from many wells pumping over a
% large area
clear; clc; close all
%------------------------------------------------------------------------
% sets useful sizes
fsize=14;
msize=14;
%----------------------------------------------------------------------------
% Sets parameters
Ho = 20;                               % Initial head at the well in meters
R =2000;                               % maximum radial distance that drawdown is
calculated for away from a pumping well
localspacing = 200;                     % spacing between simulation points in
local grids around each pumping well
regionalspacing = 500;                 % gets used by regional contour map
combolength=(2*R/localspacing+1)^2;    % all possible combos of (x,y) in local
grid
combolength=round(combolength);

% just reads in the numerical values in the excel sheet
%prop=xlsread('C:\Users\knappett.GEOSAD\Dropbox\A Texas A&M\Research\2
People\Students\Active Students\Active Primary Students\Obkirchner,
Gabi\Research\Matlab\Well_Properties.xlsx');
prop=xlsread('C:\Users\Owner\Documents\MATLAB\1_15_19\Well_Properties.xlsx');
%prop = xlsread('C:\Users\bulls\OneDrive\Documents\TAMU Grad
School\Gabby\Well_Properties.xlsx'); % for Michelle
Well.prop = prop;

MINX=min(prop(:,11)); % minimum Easting value in meters
MAXX=max(prop(:,11)); % maximum Easting
MINY=min(prop(:,10)); % minimum Northing
MAXY=max(prop(:,10)); % maximum Northing
x=MINX:regionalspacing:MAXX; % Grid point x
y=MINY:regionalspacing:MAXY; % Grid point y

% This section changes the file path to read all the Well Pump Schedule
% excel sheets.
```

```
cd 'C:\Users\Owner\Documents\MATLAB\1_15_19\GCD_PumpSchedule\McMullen'

IDs=dir('*.xls');
numfiles=length(IDs);
% numfiles = 1;
% Time position 1 corresponds to April 5, 2011.
days=2722;              % total number of days recorded for each well.

% for loop number 1
for i=1:numfiles

    % Get ID name of the spreadsheet and set path to go get it.
    ID=IDs(i).name; % ID of first well in list of wells with pumping schedules
    path=['C:\Users\Owner\Documents\MATLAB\1_15_19\GCD_PumpSchedule\McMullen\'
ID];

    % Save the ID of the well which corresponds to the number i (each
    % computer will always read the list of schedules in the same order
    % each time, but this might be a different order between different
    % computers).
    ID=strtok(ID,'.');
    Well.ID{i} = ID;

    % read the well schedule and save the information.
    schedule=xlsread(path); % uploads schedule
    Well.scheduleIND{i}=find(schedule(:,2)>0); % finds all rows of schedule when
pump was turned on
    scheduleIND = Well.scheduleIND{i};
    Qt=schedule(scheduleIND,2); % gets pumping rates in m3/day from schedule. Is a
vector of length "scheduleIND"
    Well.on{i} = [scheduleIND Qt];  % saves the day number that the well is on
with the pumping rate for that day


    % this section is accounting for aquifer rebound after pumping by
    % averaging the Qt over each pump test and adding the test number days to the
end
    % of the pump test, so the pump days increase 2X but the second half of t in
the
    % drawdown calculation will run Theis_Pump_Rebound
    recov_col1 = Well.on{i}(:,1);
    recov_col2 = Well.on{i}(:,2);
    finddiff = diff(recov_col1) == 1;
        oned = strfind(finddiff',[1 0])+1;
        if isempty(oned) == 0
            oned(end) = [];
        end
        endday =  strfind(finddiff',[1 0])+1;
        endday = [oned, endday];
        startday = strfind(finddiff',[1 0])+2;

        startday= [startday , 1];
        sd1 = unique(sort([1,startday]));
        ed1 = unique(sort([length(recov_col1),endday]));
        dur = minus(ed1, sd1)+1;

        newrecov1 = zeros(max(dur),2, length(dur));
        newrecov2 = zeros(max(dur),2,length(dur));
        rebound = zeros(max(dur),2);
        aveQ = zeros(max(dur),2);
      for b = 1:length(dur)
           rebound = zeros(dur(b),2);
           aveQ = zeros(dur(b),2);
              if length(Well.on{i}(:,1)) == 1
                rebound(:,1)= (recov_col1+1:recov_col1+1);
                rebound(:,2) = mean(recov_col2:recov_col2);

                aveQ(:,1) = (recov_col1:recov_col1);
                aveQ(:,2) =  mean(recov_col2(dur(b)));
```

```
                else
                  recov_trans =
transpose(recov_col1(sd1(b)):recov_col1(sd1(b))+dur(b));
                  recov_trans= recov_trans(1:end-1);
                  aveQ(:,1) =recov_trans;
                  vec = (recov_col2(sd1(b):ed1(b)));
                  remove = unique((recov_col2(sd1(b):ed1(b))));
                  remove = sort(remove);
                  count = histc(vec(:),remove);
                  q = zeros(length(count),1);
                      for j = 1:length(count)
                          q(j) = (remove(j)*count(j));
                      end
                  countm = sum(count);
                  qsum = sum(q);
                  weightedQ = qsum/countm;
                  aveQ(:,2) =   weightedQ;

                  rebound(:,1)= (recov_col1(ed1(b)))+1:recov_col1(ed1(b))+(dur(b))';
                  rebound(:,2) = weightedQ   ;
                  aveQ(:,1) = (recov_col1(sd1(b)): recov_col1(sd1(b))+(dur(b))-1)';
                  aveQ(:,2) = weightedQ;
                end

            newrecov1(1:dur(b),:,b) = rebound;
            newrecov2(1:dur(b),:,b) = aveQ;

            newrecov3 = reshape(newrecov1(:,1,:),[],1);
            newrecov4 = reshape(newrecov1(:,2,:),[],1);


            recov = reshape(newrecov2(:,1,:),[],1);
            recov2 = reshape(newrecov2(:,2,:),[],1);


      end

            newrecov5 = [newrecov3,newrecov4];
            recov3 = [recov,recov2];
            reorg_recov = vertcat(recov3,newrecov5);
            make_new_sched = reorg_recov(any(reorg_recov,2),:);

            finddiff = diff(make_new_sched) == 1;

            [~,~,rows] = unique(make_new_sched(:,[1]),'rows');
            delete = arrayfun(@(r) rows == r & make_new_sched(:,2) <
max(make_new_sched(rows == r, 2)), 1:max(rows), 'UniformOutput', false);
            make_new_sched(any(cell2mat(delete), 2),:) = [];
            make_new_sched= sortrows(make_new_sched,1);

            Well.onNew{i}= make_new_sched;

end


for i = 1:numfiles
    % combine all days on into one vector, sorted without repeated values
    % ADO stands for "All Days On"
    if i == 1
        ADO = Well.onNew{i}(:,1);
    else
        ADO1 = Well.onNew{i}(:,1);
        ADO = [ADO; ADO1];
        ADO = sort(ADO);
        ADO = unique(ADO);
    end

    % find max number of days on, this will be used in pre-allocating space
    % for localH
    if i == 1
```

```
        maxdayson = size(Well.onNew{i},1);
        maxcounter = i;
    elseif i > 1
        if size(Well.onNew{i},1) > size(Well.onNew{maxcounter},1)
            maxdayson = size(Well.onNew{i},1);
            maxcounter = i;
        end
    end

    if i == 1
        maxdayson = (size(Well.onNew{i},1));
        maxcounter = i;
    elseif i > 1
        if size(Well.onNew{i},1) > size(Well.onNew{maxcounter},1)
            maxdayson = (size(Well.onNew{i},1));
            maxcounter = i;
        end
    end
end

% Pre-allocate space for localH
% localH is the drawdrown
% combolength allows space for all possible points on the local grid
% 4 allows for space for the variables (x,y,r,z) in this order
% numfiles allows for space to store above for each well
% maxdayson allows for space to store above information for each day the
% well could be on. For example, if Well 1 is on for 63 days but Well 2 is
% on for 32 days, there will be space for 63 days of information for Well 2
% when it only needs 32 days of space. This will mean only the first 32
% days will be filled with values, all other days will have a 0 stored
% there.
localH = zeros(combolength,4,numfiles,maxdayson);
localH_recov = zeros(combolength,4,numfiles,maxdayson);
% this section figures out which wells are on for each day out of the max
% days on.
% this section defines overlapDays, a matrix which includes all the days on in
% numerical order in the first column and then the subsequent columns are
% for each well, assigning a 1 if that well is on that day, assigning a 0
% if that well is off that day.
overlapDays = zeros(length(ADO),numfiles+1);
overlapDays(:,1) = ADO;
% for loop number 2
for i = 1:numfiles
    count = 1;
    for k = 1:length(ADO)
        if count <= length(Well.onNew{i}(:,1)) && Well.onNew{i}(count,1) == ADO(k)
%              overlapDays(k,i+1) = Well.on{i}(count,2);
            overlapDays(k,i+1) = 1;
            count = count + 1;
        else
            overlapDays(k,i+1) = 0;
        end
    end
end

%

% Hmat=zeros(length(r),1,1,length(t),combolength,1);

% for loop number 3
for i=1:numfiles

    WellInfo = Well.onNew{i};
    scheduleIND = Well.scheduleIND{i};
    difft=diff(scheduleIND); % vector of first differences between each date.
Helps to identify non-consecutive pumping days

% --------------------------------------------------------------------------
    % this section defines test, startDays, and endDays
```

```
    % a test is a series of consecutive days with a constant Qt value
    % a startDay is the first day of a new Qt value
    % an endDay is the last day of a Qt value or startDays - 1

    test = 1;
    for j = 1:length(Well.onNew{i})+1     % +1 ???
        if j == 1   % this case is saying that the first value in scheduleIND is
the first start day
            % startDays keeps track of the days that the pump turns on from
            % scheduleIND
            Well.startDays{i}(test) = Well.onNew{i}(j);
            test = test + 1;

        elseif j > 1 && j <= length(Well.onNew{i})
            if WellInfo(j,2) ~= WellInfo(j-1,2) | WellInfo(j,1) ~= WellInfo(j-
1,1)+1
                Well.startDays{i}(test) = Well.onNew{i}(j);
                Well.endDays{i}(test-1) = Well.onNew{i}(j-1);
                test = test + 1;
            end
        elseif j == length(Well.onNew{i})+1   %+1     % only does this on the last
iteration
            Well.endDays{i}(test-1) = Well.onNew{i}(j-1);
        end

        % for the last endDay value j = length(scheduleIND), this should
        % only be evaluted once
        if j == length(Well.onNew{i})
            Well.endDays{i}(test-1) = Well.onNew{i}(end);
        end
    end

    % this calcualtes the number of days each well (i) is on for each test
    Well.pumpduration{i} = Well.endDays{i} - Well.startDays{i} + 1;

% -------------------------------------------------------------------------

    % well property stuff. Is static.
    ID=str2num(Well.ID{i});
    Ind=find(prop(:,1)==ID); % row where the ID is located on the list of
properties table
    T=prop(Ind(1),5); % transmissivity of aquifer
    S=prop(Ind(1),8); % storativity of aquifer
    X=round(prop(Ind(1),11),-1); % Easting of pumping well, rounded to nearest 10
meters
    Y=round(prop(Ind(1),10),-1); % Northing of pumping well
    Well.pumpwellpos{i} = [X Y];

    Wloc=[X Y]; % location of well in Easting and Northing
    x=(X-R):localspacing:(X+R); % Grid point x
    y=(Y-R):localspacing:(Y+R); % Grid point y
    minx=min(x); % minimum x value in local grid around a single pumping well
    miny=min(y);
    maxx=max(x);
    maxy=max(y);

    combvec = zeros(2,length(x)*length(y));
    count = 1;
    while count <= length(y)
        combvec(1,(length(x)*(count-1)+1):length(x)*count) = x;
        combvec(2,(length(x)*(count-1)+1):length(x)*count) =
y(count)*ones(1,length(x));
        count = count + 1;
    end
    posmat=transpose(combvec); % position matrix of all possible combinations of x
and y positions in local grid
% calculate distance from pumping well
    for k=1:length(posmat)
```

```
        Dx=Wloc(1)-posmat(k,1); % distance in x direction between pumping well and
grid coordinate
        Dy=Wloc(2)-posmat(k,2); % distance in y direction between pumping well and
coordinate
        posmat(k,3)=(Dx^2 + Dy^2)^0.5; % hypoteneuse distance
    end

    dayson = size(Well.onNew{i},1);
    posmat = repmat(posmat,1,1,1,dayson); % replicates position matrix into all
days of localmat
    localH(:,1:3,i,1:dayson) = posmat;

% ----------------------------------------------------------------------
% in this section, trying to evaluate Theis_Pump function and save the
% information into localH

% Theis_Pump requires the following inputs: the radius, storativity,
% transmitsivity, time (the hard one), Ho (constant value), Qt.

% time is local to consecutive pumping days. This means some tests will
% need to be combined because pumping rate may change during consecutive
% pumping days.

% Theis_Pump outputs z to be stored in localH for the index of the day on
% it is associated with. (Can be found in Well.on{i}).

    testnum = length(Well.pumpduration{i}); % defines how many tests there are for
this well
    k = 1; % gets the number of tests for this well
    tIND = 1;   % this keeps track of the index for the day in Well.on that we
want to be looking at

    % only proceed if k has not exceed total number of tests (prevent
    % indexing errors).
    while k <= testnum

        % first start going down the list of days on for the well and see
        % if a startDay has been found so we can grab the Qt value needed
        % for Theis_Pump.
        if Well.onNew{i}(tIND,1) == Well.startDays{i}(k)  % trying to figure out
which day is the test start day so we can grab the Qt from that day
            Qtvec = Well.onNew{i}(tIND,2);   % here's the Qt value for this test!
            Qt = Qtvec;                     % this assigns the Qt to be used in
Theis_Pump for now
            tmax = Well.pumpduration{i}(k); % this assigns the max number of local
time to be used in Theis_Pump for now

            % now we lookin for consecutive tests!!!!
            % these get reset after finding a stand alone test or after
            % finding the end of consecutive tests.
            kconsec1 = 1; % this is the counter to determine the number of tests
with consecutive days
            kconsec2 = 2; % keep this = kconsec1+1 unless if a standalone test or
want to end adding tests together (aka if you want to stop combining tests, making
them consecutive)

            % this while loop CONTINUES if a consecutive test has been
            % found! It will always begin b/c we assign kconsec2 > kconsec1
            % initially since we do not know yet if there is a consecutive
            % test.
            % a standalone test can be found through the logic inside of
            % this while loop! Be patient it will be found and then it will
            % exit this loop.
            while kconsec2 > kconsec1

                    if k == testnum
                        tmax = Well.pumpduration{i}(k);
                        kconsec2 = kconsec2 - 1;    % this will end the while loop
                        kconsec2 = kconsec1;
                        for t = 1:tmax
```

```
                            % posmat(a,b,c,d) where a is the grid cell number, b
is
                            % the parameter (x,y,r,z) so 3 = r, c is the well, d
is
                            % the day on
                            if t <= (tmax/2)
                                Well.Hmat{i} =
Theis_Pump(localH(:,3,1,1),S,T,t,Ho,Qt); % drawdown for all r's from pumping well
                                localH_end =  Well.Hmat{i};
                            else
                                Well.Hmat_recov_pump{i} =
Theis_Pump(localH(:,3,1,1),S,T,t,Ho,Qt);
                                recov_time = (t-(tmax/2));
                                Well.Hmat_recov{i} =
Theis_Pump_Rebound(localH(:,3,1,1),S,T,recov_time,Ho,Qt);
                                Well.Hmat{i} =  Well.Hmat_recov_pump{i} +
Well.Hmat_recov{i};
                            end

                            localH(:,4,i,tIND) = Well.Hmat{i}(:);
                            tIND = tIND + 1;

                        end

                    elseif (k + kconsec1) > testnum
                            kconsec2 = kconsec2 - 1;

                    else
                    % there is a special case for k == testnum below
                    if k < testnum

                        if (Well.endDays{i}(k+(kconsec1-1))+1) ==
Well.startDays{i}(k+(kconsec1-1)+1)
                            kconsec1 = kconsec1 + 1;
                            kconsec2 = kconsec2 + 1;    % this will keep the while
loop going

                            % do the following when kconsec1 > 1

                            % let the hard coding begin...
                            if kconsec1 < 3
                                for t = 1:Well.pumpduration{i}(k)
                                    tmax = Well.pumpduration{i}(k);
                                    if t <= round((tmax/2))
                                        Well.Hmat{i} =
Theis_Pump(localH(:,3,1,1),S,T,t,Ho,Qt); % drawdown for all r's from pumping well
                                        localH_end =  Well.Hmat{i};
                                    else
                                        Well.Hmat_recov_pump{i} =
Theis_Pump(localH(:,3,1,1),S,T,t,Ho,Qt);
                                        recov_time = (t-(tmax/2));
                                        Well.Hmat_recov{i} =
Theis_Pump_Rebound(localH(:,3,1,1),S,T,recov_time,Ho,Qt);
                                        Well.Hmat{i} = Well.Hmat_recov_pump{i} +
Well.Hmat_recov{i};
                                    end

                                    localH(:,4,i,tIND) = Well.Hmat{i}(:);
                                    tIND = tIND + 1;

                                end

                                tend =
(Well.pumpduration{i}(k)+Well.pumpduration{i}(k+1));
%Well.pumpduration{i}(k+kconsec1-1));

                                % for the ith Well and kth test, gets the current
study time,
                                % studyt
                                for t = 1:(Well.pumpduration{i}(k+1))     %  :tend
```

```
                                    tmax = Well.pumpduration{i}(k+1);
                                    % posmat(a,b,c,d) where a is the grid cell
number, b is
                                    % the parameter (x,y,r,z) so 3 = r, c is the
well, d is
                                    % the day on
                                    if t <= (tmax/2)
                                        Well.Hmat{i} =
Theis_Pump(localH(:,3,1,1),S,T,t,Ho,Qt); % drawdown for all r's from pumping well
                                        localH_end =  Well.Hmat{i};
                                    else
                                        Well.Hmat_recov_pump{i} =
Theis_Pump(localH(:,3,1,1),S,T,t,Ho,Qt);
                                        recov_time = (t-(tmax/2));
                                        Well.Hmat_recov{i} =
Theis_Pump_Rebound(localH(:,3,1,1),S,T,t,Ho,Qt);
                                        Well.Hmat{i} = Well.Hmat_recov_pump{i} +
Well.Hmat_recov{i};
                                    end

                                    localH(:,4,i,tIND) = Well.Hmat{i}(:);
                                    tIND = tIND + 1;

                                end
                            end

                            if kconsec1 >= 3

                               tmax =  Well.pumpduration{i}(k+(kconsec1-2)+1);
                               tstart = tend+1;
                               tend = tend + Well.pumpduration{i}(k+kconsec1-1);

                               % for the ith Well and kth test, gets the current
study time,
                                % studyt
                               for t = 1:tmax                                       %
posmat(a,b,c,d) where a is the grid cell number, b is
                                    % the parameter (x,y,r,z) so 3 = r, c is the
well, d is
                                    % the day on
                                    if t <= round(tmax/2)
                                        Well.Hmat{i} =
Theis_Pump(localH(:,3,1,1),S,T,t,Ho,Qt); % drawdown for all r's from pumping well
                                        localH_end =  Well.Hmat{i};
                                    else
                                        Well.Hmat_recov_pump{i} =
Theis_Pump(localH(:,3,1,1),S,T,t,Ho,Qt);
                                        recov_time = (t-(tmax/2));
                                        Well.Hmat_recov{i} =
Theis_Pump_Rebound(localH(:,3,1,1),S,T,recov_time,Ho,Qt);
                                        Well.Hmat{i} = Well.Hmat_recov_pump{i} +
Well.Hmat_recov{i};
                                    end

                                    localH(:,4,i,tIND) = Well.Hmat{i}(:);
                                    tIND = tIND + 1;

                               end
                             end
% -------------------------------------------------------------------------
%   THIS GETS USED NOW   case if no consecutive tests, just one stand alone test
                        elseif kconsec1 == 1
                            tmax = Well.pumpduration{i}(k);
                            kconsec2 = kconsec2 - 1;    % this will end the while
loop
                            for t = 1:tmax
                                % posmat(a,b,c,d) where a is the grid cell number,
b is
```

```
                                % the parameter (x,y,r,z) so 3 = r, c is the well,
d is
                                % the day on
                                if t <= (tmax/2)
                                    Well.Hmat{i} =
Theis_Pump(localH(:,3,1,1),S,T,t,Ho,Qt); % drawdown for all r's from pumping well
                                    localH_end =  Well.Hmat{i};
                                else
                                    Well.Hmat_recov_pump{i} =
Theis_Pump(localH(:,3,1,1),S,T,t,Ho,Qt);
                                    recov_time = (t-(tmax/2));
                                    Well.Hmat_recov{i} =
Theis_Pump_Rebound(localH(:,3,1,1),S,T,recov_time,Ho,Qt);
                                    Well.Hmat{i} = Well.Hmat_recov_pump{i} +
Well.Hmat_recov{i};
                                end

                                localH(:,4,i,tIND) = Well.Hmat{i}(:);
                                tIND = tIND + 1;
                            end
% ------------------------------------------------------------------------
% this section ends the consecutive test counting.
                        else
                            % by subtracting 1 from kconsec2, kconsec2 should
                            % become equivalent to kconsec1, thus ending the
                            % while loop condition that kconsec2 > kconsec1
                            kconsec2 = kconsec2 - 1;

                        end
% ------------------------------------------------------------------------
% if k == testnumber, then the only way k could == testnumber is if the last test
is stand alone,
% otherwise it would've been added to a previous k in the kconsec stuff
                    elseif k  == testnum
                        tmax = Well.pumpduration{i}(k);

                        for t = 1:tmax
                            %cd 'C:\Users\bulls\OneDrive\Documents\TAMU Grad
School\Gabby\'; % for Michelle
                            % posmat(a,b,c,d) where a is the grid cell number, b
is
                            % the parameter (x,y,r,z) so 3 = r, c is the well, d
is
                            % the day on
                            if t <= (tmax/2)
                               Well.Hmat{i} =
Theis_Pump(localH(:,3,1,1),S,T,t,Ho,Qt); % drawdown for all r's from pumping well
                               localH_end =  Well.Hmat{i};
                            else
                                Well.Hmat_recov_pump{i} =
Theis_Pump(localH(:,3,1,1),S,T,t,Ho,Qt);
                                recov_time = (t-(tmax/2));
                                Well.Hmat_recov{i} =
Theis_Pump_Rebound(localH(:,3,1,1),S,T,recove_time,Ho,Qt);
                                Well.Hmat{i} =  Well.Hmat_recov_pump{i} +
Well.Hmat_recov{i};
                            end

                            localH(:,4,i,tIND) = Well.Hmat{i}(:);   % doesn't go
to this line until k = 10, tIND = 58!
                            tIND = tIND + 1;
                        end
                        kconsec2 = kconsec2 - 1;
                    end

                end

% ------------------------------------------------------------------------
```

```
            end % end for while kconsec2 > kconsec1 (true when the next test
(k+kconsec1+1) is a consecutive test)
            % index to go to next set of nonconsecutive test
            k = k + kconsec1;
        end

    end % end for while k <= testnum
% -------------------------------------------------------------------------
 Well.localHxy{i}= localH(:,1:2);


end% end for for i:numfiles

clc;
Well
```