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Spatial and Temporal Impacts on Water Consumption in Texas from Shale Gas Development and Use

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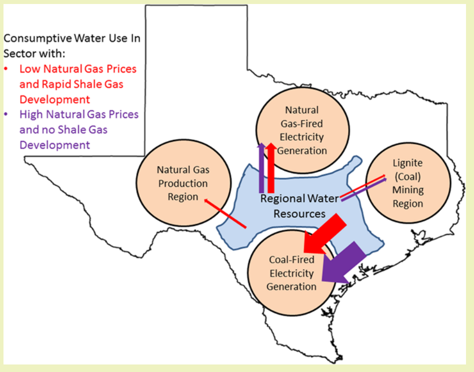
Supporting Information

ABSTRACT: Despite the water intensity of hydraulic fracturing, recent life cycle analyses have concluded that increased shale gas development will lead to net decreases in water consumption if the increased natural gas production is used at natural gas combined cycle power plants, shifting electricity generation away from coal-fired steam cycle power plants. This work expands on these studies by estimating the spatial and temporal patterns of changes in consumptive water use in Texas river basins during a period of rapid shale gas development and use in electricity generation from August 2008 through December 2009. While water consumption decreased in Texas overall, some river basins saw increased water consumption and others saw decreased water consumption, depending on the extent of extraction activity in the basin, the mix of power plants using cooling water in that basin, and price-based changes in the power sector. Due to the temporal and spatial heterogeneity in the consumptive water impacts of natural gas development and use in the power sector, local and regional water use impacts must also be considered in addition to the overall supply chain impacts.



KEYWORDS: *Shale gas, Water use, Electricity, ERCOT, Texas*

INTRODUCTION

Total natural gas production in the United States is expected to increase by 44% between 2011 and 2040, with shale gas development being the largest source of growth.[1] Recently, shale gas extraction has increased due to advances in hydraulic fracturing and horizontal drilling that have enabled economical production of natural gas from shale formations. Shale gas plays in Texas, particularly the Barnett Shale in the Dallas−Fort Worth area, were among the first shale gas resources in the country developed on a large scale,[1] and the state accounted for 66% of the shale gas production in the United States from 2008 to 2009.[2] Texas is also predominantly served by a largely self-contained electric grid, the Electricity Reliability Council of Texas (ERCOT), which has significant natural gas generation capacity. Thus, Texas is an important early case study for the development and utilization of shale gas resources for electricity generation.

The rapid development of shale gas resources in the United States has occurred, while research on its environmental impacts, such as water quantity,[3−7] water quality,[8−11] air quality,[12−14] and greenhouse gas emissions[15−17], is ongoing. Previous studies on total water consumption in natural gas production have focused on quantifying the total water used[4,6] or available[5] for shale gas production in a particular region, without examining changes to water demand associated with changes in electricity generation. In addition, life cycle analyses of the consumptive water impacts of shale gas development and use in electricity generation[3,7] have generally assumed that the natural gas is used exclusively to displace coal-fired generation. However, not all marginal natural gas production will necessarily be used to displace coal-fired power generation. In 2011, 48% of the total natural gas consumption in Texas,[18] which included natural gas from both new and existing wells, occurred in the power generation sector.

Prior work on water use in natural gas supply and use chains in Texas found that higher water requirements at the point of natural gas extraction could be offset by water savings due to higher power plant efficiency, cooling system design, and avoided emissions controls at the point of electricity production. These analyses have assumed that conventional coal-fired generation is displaced by natural gas combined cycle units, resulting in net water consumption reductions.[3] In

Received: April 7, 2014
Revised: June 23, 2014
Published: June 24, 2014

practice, the extent to which natural gas from shale production displaces conventional coal-fired generation is controlled by many factors, including operational parameters at the power plant and the relative price of coal and natural gas.[12,13] In addition, shifts in power generation might be located in different regions than shale gas production, resulting in shifts in the spatial distribution of water consumption. Thus, the water savings due to decreased water consumption in coal-fired electricity generation and coal mining might occur at different locations or times than where and when water is used for natural gas production. Unfortunately, the location and timing of these changes in water consumption are not known because both a control case without shale gas development and the actual natural gas use due to shale gas development cannot both be known.

To address this knowledge gap, this study will estimate the spatial and temporal characteristics of changes in consumptive water use in Texas during a period of rapid shale gas development that triggered decreased natural gas prices, enabling greater use of natural gas in the electricity generation mix.[10] In particular, this study will estimate the extent to which water consumption for hydraulic fracturing in natural gas production regions was offset by reductions in the consumptive water use in electricity generation and lignite (coal) mining in Texas and in specific river basins in the state in order to determine whether local changes differ from state-wide and supply chain impacts.

■ MATERIALS AND METHODS

The analysis in this work quantifies shifts in consumptive water use in Texas that were driven by changes in natural gas production and price in the state during the period from August 2008 through December 2009. During this time, the price of natural gas for electric power producers dropped from $11.09 per million British thermal units (MMBTU) to less than $4 per MMBTU,[19] as shown in Figure S1 of the Supporting Information, while total shale gas production in Texas increased by 14%.[2] This work compares two cases (Table 1). Scenario 1 is an actual development scenario that uses historic natural gas prices, production, and well completion data. Scenario 2 is a hypothetical alternative development scenario in which hydraulic fracturing of horizontal wells in the Barnett Shale and section of the Haynesville Shale in Texas, the most active areas for new shale gas activities in eastern Texas during this period, is assumed not to have occurred after July 31, 2008. In the alternative scenario, the natural gas price for electricity producers in the state was assumed to remain constant at $11.09 per MMBTU, which was the July 2009 price.[19] This price point is used as a plausible scenario to estimate the behavior of ERCOT at high natural gas prices. However, a full economic analysis, including second-order effects and price inelasticities, of the impact of the forgone production from these horizontal wells, which accounted for 9.2% of total natural gas production in Texas during the period, is beyond the scope of this work.

Table 1. Summary of Scenario Assumptions for Price of Natural Gas in Power Sector and Well Completion Activity in Shale Gas Production Regions in Texas from August 2008 through December 2009

Scenario	Price of natural gas for the power sector	New natural gas wells in the Barnett Shale and Texas part of the Haynesville Shale
1	monthly average natural gas price for Texas[19] from August 2008 to December 2009 (Figure S1, Supporting Information)	actual rate of well completion during study period[26]
2	constant price of $11.09 per MMBTU	no new horizontal wells completed after July 31, 2008

For this work, consumption, which is the amount of water taken from a water reservoir but not returned to it,[20,21] was chosen as the benchmark water metric rather than withdrawals, which is the total amount of water taken from the source,[20,21] so that comparisons could be made to recent studies,[3,4,7] which have focused on freshwater consumption. While water withdrawals and consumption can vary by orders of magnitude for power plant cooling, at the point of extraction in the natural gas production sector in Texas, water consumption and withdrawals have historically been similar due to limited reuse of water resources.[4] Thus, consumptive water use was determined to be the appropriate metric of comparison of the water impacts in the lignite mining and power generation sectors.

Spatial Domain. The total change in water consumption from ERCOT, lignite (the type of coal produced in Texas) mining, and natural gas production between the two scenarios was estimated for Texas and for each river basin in the state.[22] These boundaries match the spatial domain used in recent research on Texas water rights modeling.[23,24] Each power plant, horizontal gas well, and lignite mine examined in this study was mapped to a specific water basin in Texas[22] based on its latitude and longitude using ArcGIS Version 10.1.[25]

Water Consumption in Natural Gas Production. For this study, horizontal natural gas wells that were drilled in Texas in the Haynesville Shale and Barnett Shale plays during the study period were identified using the commercially available IHS database.[26] This database contained the location (latitude and longitude), completion date, and monthly production of each well in the region. During this period, 2996 horizontal gas wells were completed in the Barnett Shale (2664 wells) and the Texas part of the Haynesville Shale (332 wells), and these wells accounted for 9.2% of the total natural gas produced in Texas during this period. The spatial location of each well is shown in Figure S2 of the Supporting Information. For the actual natural gas production and prices scenario (Scenario 1), the water consumed during hydraulic fracturing at each horizontal well was estimated using a play median factor of 2.8 million gallons per well for the Barnett Shale and 5.7 million gallons per well in the Haynesville Shale.[4] Implications and rationale for the use of the play median factors rather than individual well water consumption is listed in Table S1 of the Supporting Information. For the alternative scenario (Scenario 2), the assumption that no horizontal wells were completed after July 31, 2008 was made, and thus, water use in hydraulic fracturing of horizontal wells during the study period was assumed to be negligible. Thus, the difference in water consumed in natural gas production between the two scenarios was assumed to be equal to the amount of water used in hydraulic fracturing of the horizontal wells in the actual development scenario (Scenario 1). While there are other upstream water uses, such as for drilling and for proppant production,[4] Laurenzi and Jersey[7] found that water consumed in these activities was small compared to hydraulic fracturing, which was 89% of upstream natural gas water consumption, and that all upstream water consumption, including hydraulic fracturing, was small compared to the power plant, which accounted for 93% of lifecycle water consumption.

Recently, the Eagle Ford Shale in south Texas has experienced rapid growth in natural gas production. However, for the period examined in this study, total production from the Eagle Ford Shale was much less than 0.01% of the total natural gas produced in Texas,[27] and by the end of 2009, the total number of gas wells in the region was small (only 67)[27] compared to more developed natural gas production regions, such as the Barnett Shale, which had more than 10,000 natural gas wells.[28] Thus, the exclusion of the Eagle Ford Shale from the analysis is not expected to have a significant impact on the results of this study. Implications of changes in consumptive water use in the lignite and power production sectors in the river basins in the Eagle Ford Shale, however, are discussed in this work.

Water Consumption in Electricity Generation. For each scenario, the hourly generation at each electricity generating unit (EGU) in ERCOT was determined using a PowerWorld[29] model that has been used in previous studies.[13,30,31] This model includes constraints on generator minimum and maximum generation levels, total demand in ERCOT, ramp rate, and transmission line capacity but does not include constraints on facility maximum capacity factor. In the electricity generation model, the price of natural gas was the only variable changed between simulations for Scenario 1, in which the monthly average natural gas price for Texas power producers was used (Figure S1, Supporting Information), and Scenario 2, in which a constant price of $11.09 per MMBTU was applied across the study period. Hourly electricity production in ERCOT was equivalent in Scenarios 1 and 2. More information on the PowerWorld model and its performance in estimating the fuel mix for ERCOT, which was equivalent to a similar model in the literature,[12] is available in the Supporting Information.

Water consumption at each power plant in ERCOT was determined by multiplying the generation by EGU-specific annual-average consumption factors[32] that were developed for the Texas Water Development Board (TWDB). Using Texas-specific factors for power plant consumptive water use is important because a recent study[33] found higher consumption rates at natural gas-fired power plants in Texas than national average values.[20,21] Compared to using other publicly available databases that utilize a national average[21] or a Texas average[33] value for the consumptive water use rate at each power plant based on its cooling system configuration, the use of the power plant-specific database from King et al,.[32] which is the database used in this study, leads to the smallest estimate of water savings in the power sector from the displacement of coal-fired units with natural gas-fired power plants (Figure S3, Supporting Information). For Texas water consumption databases, the King et al.[32] database differs from the Scanlon et al.[33] factors because the King et al.[32] database provides specific water consumption estimates for each power plant rather than an average for each power plant cooling system configuration type (for example, recirculating cooling towers for natural gas combined-cycle plants). Thus, the King et al.[32] factors account for different power plant cooling requirements based on factors such as local climate and power plant efficiency. In addition, it is important to note that consumption rates would vary with meteorological conditions, but this study does not estimate meteorological deviations from annual average consumption values for each EGU.

Multiple sectors drive demand for the production of natural gas in Texas, and this study estimates the water consumed in shale gas production regardless of whether the natural gas produced is actually used in electricity generation in ERCOT. Because the amount of additional gas produced in Scenario 1 compared to Scenario 2 is greater than the additional amount of natural gas used in the power sector in Scenario 1 compared to Scenario 2, the excess gas may have been used in power generation or other applications in other parts of the United States. In this circumstance, this work estimates the water used in the production of the natural gas in Texas but not the water savings from the power sector in other states. This distinction might lead to a reduced estimate of total consumptive water savings from the use phase of the natural gas life cycle because this study only considers local consumptive water changes in ERCOT's boundaries within the state of Texas. In addition, changes to natural gas use in other sectors (e.g., chemical manufacturing), which might not provide the same level of change in local water consumption in producing regions in Texas as the power generation sector, are not estimated in this study.

Water Consumption in Lignite (Coal) Production. Fuel for coal-fired power generation in Texas comes from a combination of lignite for mine-mouth power plants and sub-bitumous coal from the Powder River Basin in Wyoming, which is transported to Texas by rail and is more energy dense than lignite. In Texas, some plants burn exclusively lignite or coal, while others utilize a mixture of coal types. For 2009, the fraction of lignite and sub-bitumous coal on a heat basis (MMBTU) was calculated from fuel receipt data[34] for each power plant in ERCOT. In 2009, sub-bitumous coal from Wyoming accounted for 68% of the total coal used in ERCOT on a heat basis and 62% on a mass basis.

For this study, upstream water consumption changes were limited to changes in coal production associated with lignite consumption at Texas power plants in ERCOT. Exclusion of the water impacts in Wyoming from changes in the ERCOT demand for sub-bituminous coal is consistent with methodology of other recent studies of the water impacts of energy production in Texas[3,4] because the water consumption occurs outside of the state boundary. On the basis of analysis of data from the United States Energy Information Administration (EIA),[34] seven coal-fired power plants in ERCOT used some lignite as a fuel source in 2009, and each power plant was supplied by its associated nearby lignite mine. For each scenario, the total heat provided by lignite at each of the seven power plants for August 2008 through December 2009 was calculated to determine the total demand for lignite from ERCOT and to establish the upstream production rate of lignite needed for power plant fuel, assuming that the ratio of sub-bitumous coal to lignite coal remained constant at these facilities with changing generation. A recent study[3] found that the production of Powder River Basin coal in Wyoming was 3–17% as water intensive as lignite production in Texas and established a consumptive water use factor for lignite production in Texas of 16.1 gal per MMBTU, which included mine dewatering per convention by Texas water policymakers. Water consumption for truck transporting of lignite within Texas and for the Texas portion of the rail transport of Powder River Basin coal from Wyoming were considered negligible in this study.[3]

dx.doi.org/10.1021/sc500236g | ACS Sustainable Chem. Eng. 2014, 2, 2028–2035

RESULTS AND DISCUSSION

Net Impacts on Consumption in Texas. In Texas, between August 2008 and December 2009, total water consumption in the actual natural gas prices and production scenario (Scenario 1) was found to be 1.1 billion gallons less than in Scenario 2 (Table 2), including changes in both the electricity generation and the fuel production sectors in the state. These savings are equivalent to 0.4% of the TWDB estimate[35] for the total water consumed in Texas for mining, which includes natural gas and coal production activities, and power generation during the period examined in this study. As noted in the Materials and Methods section, this estimate may understate overall water savings.

Table 2. Net Changes in Consumptive Water Use by Sector in Texas from August 2008 through December 2009[a]

Water consumption category	Net consumption August 2008−December 2009 (billion gallons)		
	Scenario 1	Scenario 2	Net change for Scenario 1 compared to Scenario 2
hydraulic fracturing of horizontal wells	9.4	0.0	+9.4
lignite mining for ERCOT generation	7.7	9.9	−2.2
net consumption by ERCOT power plants for electricity generation			
coal	68.3	84.1	−15.8
natural gas combined cycle (NG-CC)	34.3	27.1	+7.2
natural gas steam turbine (NG-ST)	2.0	1.6	+0.5
natural gas combustion turbine (NG-GT)	0.6	0.6	−0.0
other fuel types	36.9	37.1	−0.2
ERCOT total	142.1	150.4	−8.3
net total	159.2	160.3	−1.1

[a]Scenario 1 included actual natural gas prices and production in the state. Scenario 2 used an elevated natural gas price and assumed no horizontal well completions via hydraulic fracturing after July 31, 2008. Note that negative values indicate a sector in which Scenario 1 has less water consumption (i.e., a net water savings) compared to Scenario 2. Note that values may not sum to the first decimal place due to rounding in calculations.

Much of the potential water savings calculated in this study (Figure 1 , Table 2) and estimated in other studies[3,7] are driven by changes in the fuel mix utilized in the electricity generation sector. Compared to Scenario 2, lower natural gas prices in Scenario 1 caused a shift of 9% of ERCOT total generation from coal-fired to natural gas-fired EGUs, including steam cycle, combined cycle, and combustion turbine plants (Figure S4, Supporting Information). Under the actual natural gas prices scenario (Scenario 1), demand for natural gas in ERCOT increased by 0.3 trillion cubic feet (tcf), which was less than the 1.0 tcf of additional natural gas (9.2% of total Texas natural gas production) produced at the horizontal wells completed in the Barnett Shale and the portion of the Haynesville Shale in Texas during the study period. For reference, total reported natural gas usage used in all sectors in Texas[18] during the study period was 4.2 tcf, and 2.0 tcf was used in the electric power sector. Total water consumption in ERCOT for power generation was lower in the actual development scenario (Scenario 1), resulting primarily from a 15.8 billion gallon decrease in water consumption at coal-fired power plants that offset a 7.6 billion gallon increase in water consumed at natural gas EGUs, which had increased generation and cooling water usage in this scenario. In Scenario 1, decreased usage of the coal-fired power generation resources in ERCOT led to a 2.2 billion gallon savings in water consumption from lignite mining in Texas compared to Scenario 2. Water consumption from hydraulic fracturing of horizontal gas wells in the Barnett Shale and Texas

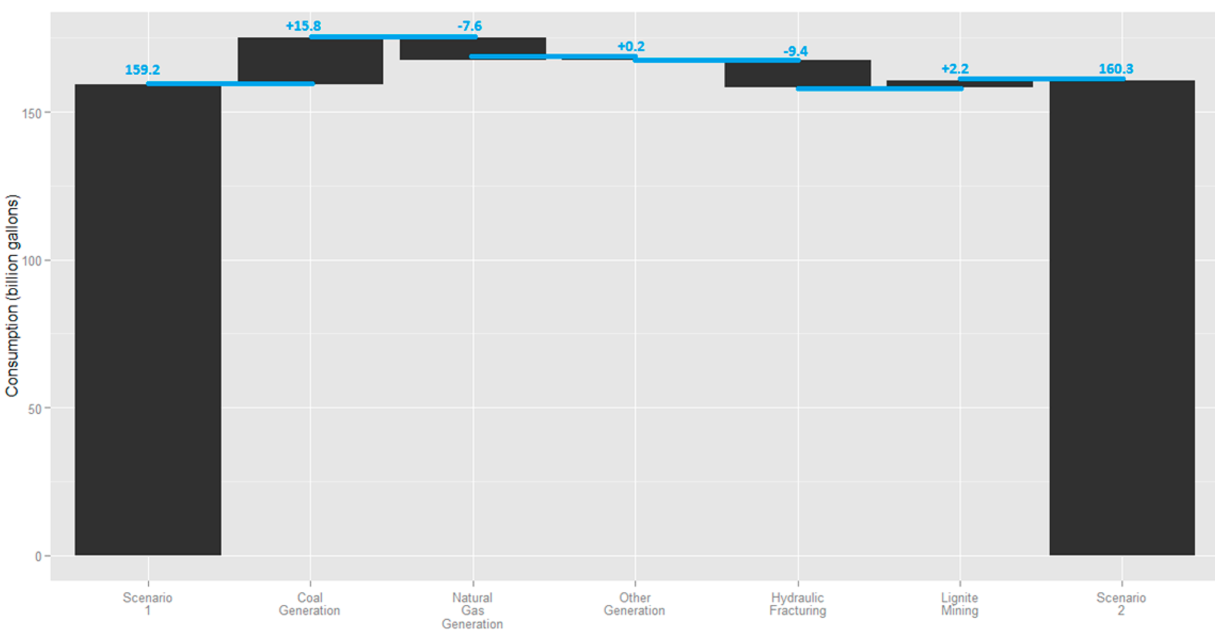


Figure 1. For Scenario 1 (actual natural gas prices and production) compared to Scenario 2 (elevated natural gas price and no new horizontal well completions in the Barnett Shale and Texas portion of the Haynesville Shale), total water consumption in the power generation and mining sectors decreased by 1.1 billion gallons between August 2008 and December 2009. Water savings from the displacement of coal-fired power generation in ERCOT by natural gas power plants and from decreased lignite mining were largely offset by water consumption for the hydraulic fracturing of horizontal wells completed during the study period. Table 2 contains a description of the consumptive water use by category for Scenarios 1 and 2.

dx.doi.org/10.1021/sc500236g | ACS Sustainable Chem. Eng. 2014, 2, 2028−2035

portion of the Haynesville Shale was 9.4 billion gallons during the study period. Water consumption in hydraulic fracturing was only considered in Scenario 1 because Scenario 2 assumed that new well completions in the state ceased after July 31, 2008. Thus, net consumption in the mining sector, which included both natural gas and lignite production, increased by 7.2 billion gallons in Scenario 1 compared to Scenario 2. Thus, the water savings for the actual development scenario (Scenario 1) during the study period from changes in ERCOT power generation (8.3 billion gallon) were largely offset by increased water consumption in the Texas mining sector (7.2 billion gallons), leading to a net savings of 1.1 billion gallons in Scenario 1.

The total consumptive water savings in ERCOT in this study (8.3 billion gallons) from the displacement of 37 TWh of coal-fired power generation by natural gas power plants is less than would be expected using factors from previous work (10.0 billion gallons).[3] This difference is due to assumptions in the previous work[3] that all the marginal gas would be used for highly efficient combined cycle plants and would only displace coal. The analysis presented in this work did not restrict the options to natural gas combined cycle plants. It included natural gas boilers, which consume water at a higher rate than natural gas combined cycle and coal EGUs[20,33] in some commonly used cooling system configurations, allowed for the possibility that power plants other than coal would be displaced, utilized time-resolved dispatching instead of average displacement assumptions, and only considered localized water consumption changes in electricity generation.

Due to the time delay between the increased water consumption at the point of extraction and subsequent decreased water consumption at the point of combustion, net consumptive water savings in Texas in Scenario 1 were not realized until a minimum of 14 months after the start of the study time frame (Figure 2). The delay in water consumption changes at the point of combustion was due to the relatively high price of natural gas in late 2008 compared to 2009. Major water savings in the power sector did not begin until February 2009 (Figure 2), when the price of natural gas in Texas decreased from \$5.12 per MMBTU \$4.32 per MMBTU (Figure S1, Supporting Information). Thus, while there are net life cycle consumptive water benefits to shale gas production and use in the electricity generation sector in place of coal-fired power plant generation,[3,7] there is likely a delay between when the water is used in shale gas production and when net water use benefits would be realized.

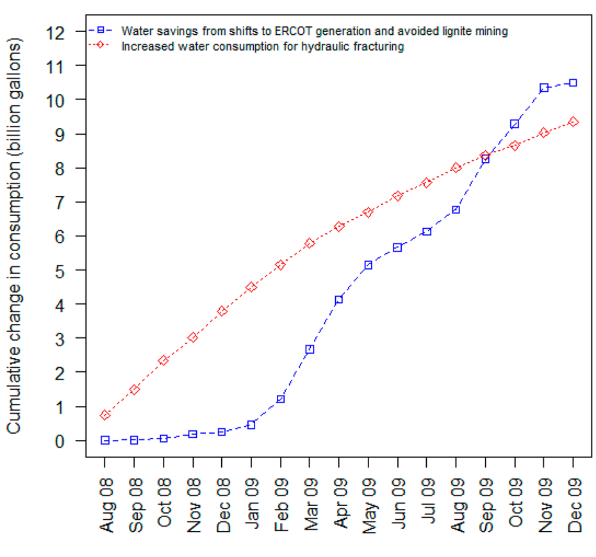


Figure 2. Comparison of the change in cumulative water consumption used in hydraulic fracturing of horizontal gas wells in the Barnett Shale and the Texas part of the Haynesville Shale to cumulative consumptive water savings in the electricity generation and lignite sectors. Note that the point of intersection in September 2009 indicates the month during which the cumulative savings in the power and lignite production sectors surpasses the net water consumed in hydraulic fracturing since the start of the study.

Net Spatial Impacts in Texas River Basins. Figure 3 shows the total change in consumptive water use for each river basin in Texas over the entire study time frame, and Figure 4 shows cumulative consumptive water changes at a monthly time resolution for selected water basins with wells completed during the study period in the Barnett Shale or the part of the Haynesville Shale located in Texas. While overall water consumption decreased in Texas (Figure 1, Table 2), water consumption increased in river basins whose boundaries included intense natural gas extraction or natural gas-based power generation activities. River basins with increased water consumption in the actual natural gas prices and production scenario (Scenario 1) had several causes: (1) insufficient coal-fired power plant capacity to offset water consumption from natural gas production (Neches river basin), (2) increased use of natural-gas EGUs (Nueces-Rio Grande river basin), or (3) both (Trinity river basin).

Within the Barnett Shale, the Brazos and Trinity river basins, which accounted for 24% and 65% of the wells completed during the study time frame, respectively, had significantly different consumptive water impacts. As shown in Figure 4, water consumption in both river basins increased at the beginning of the study period as water was used for hydraulic fracturing. The direction of changes in consumptive water use in the two regions began to diverge as the price of natural gas decreased (Figure S1, Supporting Information). While both areas experienced increased water consumption from natural gas production and use in EGUs (Table 3), the Brazos river basin has significantly higher coal-fired power plant installed capacity (5.5 GW compared to 1.2 GW) and generation (Table 3) than the Trinity river basin. When natural gas prices in the actual development scenario decreased, the reduction in water consumption at coal-fired power plants in the Brazos river basin offset increased water consumption from natural gas production and use in electricity generation. In the Trinity river basin, decreased water usage at coal-fired power plants was insufficient to offset increased water usage in the natural gas production sector. Similar patterns were observed in the Haynesville Shale with the Sabine and Cypress river basins experiencing net decreases in consumptive water use, while the Neches river basin had an increase in net consumptive water use during the study period. Thus, while several life cycle assessments[3,7] have calculated that water use would decrease with shale gas production if it was used in natural-gas fired EGUs as a replacement for coal-fired power plant generation, not all regions have sufficient coal-fired power plant generation for this displacement. Thus, the potential combined consumptive water impacts of new natural gas production and use in the power sector are likely basin-specific.

It should be noted that results from the electricity generation model for ERCOT at the \$11.09 per MMBTU natural gas price (Scenario 2) indicated that the capacity factor, which is defined

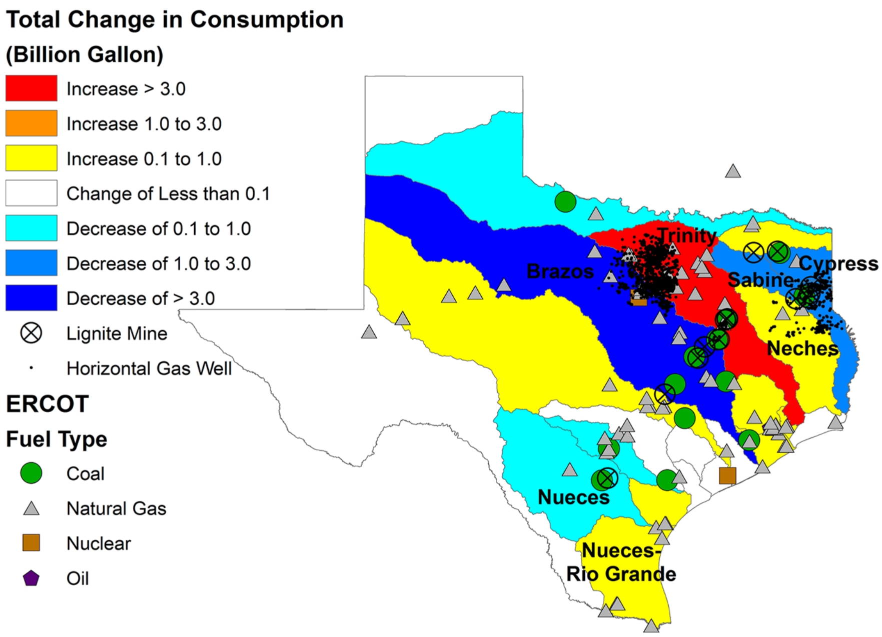


Figure 3. Change in total water consumption in Texas river basins during the August 2008 through December 2009 time frame due to hydraulic fracturing in the Haynesville Shale and Barnett Shale and water use changes in the ERCOT and lignite production sectors. Red to yellow areas indicate regions with increased water consumption in the scenario with actual natural gas prices and production (Scenario 1) compared to the case in which natural gas prices in the state remained elevated (Scenario 2).

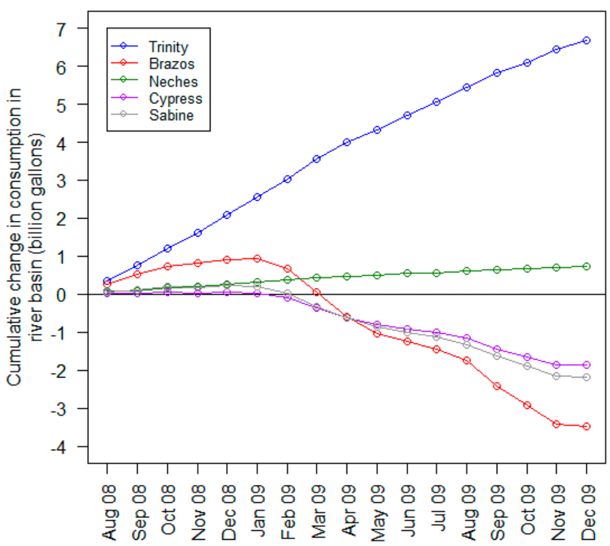


Figure 4. Change in cumulative water consumption (billion gallons) in selected river basins from the start of the study period (August 2008) reported monthly. Note that negative values indicate a net reduction in consumption in the river basin since the start of the study in the scenario with actual natural gas prices (Scenario 1) compared to the scenario (Scenario 2) with a constant $11.09 price for natural gas.

as the fraction of nameplate generation that is utilized during a period, of coal-fired power plants would be 1. In practice, power plants do not usually operate at 100% capacity for the length of the study period examined in this work due to down time for scheduled maintenance and facility constraints. During historic periods with high natural gas prices and consumer demand for electricity, the utilization of coal-fired power generation capacity has been high. During July 2008 when the natural gas price for Texas power producers was at $11.09 per MMBTU, for example, the fleet of coal-fired power plants in ERCOT operated at 90% of its nameplate capacity.[34] By comparison, the ERCOT coal-fired power generation was 86% of capacity in July 2009, when the price of natural gas was $3.69 per MMBTU.[34]

While other electricity generation models[36] have included constraints on maximum capacity factor, that complexity has not been included in the Power World model used in this study and other previously published research[13,30,31] that was developed with a focus on characterizing transmission constraints within ERCOT. The model result of 100% utilization of coal generation capacity in Scenario 2 indicated that at the $11.09 per MMBTU price for natural gas, it would be financially feasible to operate any available coal-fired power plant at the maximum available capacity due to the relatively low fuel price compared to natural gas and that ERCOT would utilize such capacity. The development of a maximum capacity factor within the PowerWorld model for ERCOT electricity generation would likely lead to decreased estimates of consumptive water use from the power sector in Scenario 2 (and thus lower potential water savings for Scenario 1) due to increased utilization of natural gas-fired power plants (in particular, NG-CC plants as shown in Table 2) and decreased utilization of coal-fired power plants, but the development of such a model is beyond the scope of this work. This simplification might impact the precise magnitude of the outcomes discussed in this work but would not affect the trends or the central conclusions that there are likely spatial and temporal variations in consumptive water patterns occurring as a result of increased natural gas production and use in Texas.

Implications for Other Production Regions. During a period of rapid shale gas development and use in the electricity generation sector in Texas, net water consumption in the state decreased slightly due to displacement of coal-fired power plant generation by natural gas EGUs, which tend to have less water-intensive operations.[37] However, water consumption might increase in some areas where new natural gas production and

dx.doi.org/10.1021/sc500236g | ACS Sustainable Chem. Eng. 2014, 2, 2028−2035

Table 3. Net Consumptive Water Use by Category from August 2008 through December 2009 for Selected River Basins with Natural Gas Production Activities

	Water consumption for hydraulic fracturing (billion gallons)		Water consumption for lignite mining (billion gallons)		ERCOT natural gas EGUs				ERCOT coal EGUs			
					Generation (TWh)		Water consumption (billion gallons)		Generation (TWh)		Water consumption (billion gallons)	
River basin	Scenario 1	Scenario 2	Scenario 1	Scenario 2	Scenario 1	Scenario 2	Scenario 1	Scenario 2	Scenario 1	Scenario 2	Scenario 1	Scenario 2
Brazos	2.01	0.00	2.99	3.74	13.3	10.2	3.1	2.3	55.2	68.4	28.8	35.9
Trinity	5.45	0.00	0.92	1.15	35.6	27.6	6.6	5.1	11.5	14.3	3.3	4.1
Sabine	0.89	0.00	3.19	4.22	5.1	3.9	1.2	0.9	20.1	28.0	7.2	10.0
Cypress	0.28	0.00	0.61	0.79	0.1	0.1	0.0	0.0	18.3	23.4	4.0	5.1
Neches	0.72	0.00	0.00	0.00	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0

natural gas-based electricity generation is not locally offset by decreases in coal-based electricity generation. Thus, there can be spatial and temporal variations in the impacts of shale gas development and use, which are important to consider, in addition to the overall supply chain impacts, when examining the potential impacts of shale gas development on water resources. The methodology outlined in this work could be applied to other regions, which would likely have different spatial distributions and water use intensities for power generation and fuel production.

For this work, the focus of the power sector analysis is on short-term price-based changes in the dispatch order in ERCOT before new power plants could be constructed. Over the long-term, the retirement of older coal-fired power plants and the construction of new natural gas combined cycle power plants in Texas may also be a driver of changes in the spatial location and magnitude of cooling water consumption within the state. The long-term driver may cause shifts in consumption at different spatial locations than the shifts observed in this analysis. Estimating the impact of retirements and new construction power plants, however, is beyond the scope of this work.

The conclusion that some river basins may experience increased water consumption, despite overall decreases in water consumption along the natural gas production and electricity generation supply chain, has important implications in new natural gas development areas, including the Eagle Ford Shale. The Nueces-Rio Grande and Nueces river basins in south Texas (Figure 2) each contain parts of this play, and the changes in consumptive water use examined in these river basins were driven entirely by changes in ERCOT because the natural gas production in the area was minimal during the study period. Compared to Scenario 2, the consumptive water use in the actual natural gas prices scenario (Scenario 1) was 0.5 billion gallons less in the Nueces river basin and 0.5 billion gallons higher in the Nueces-Rio Grande basin. In the Nueces river basin, decreased consumption at a coal-fired power plant and its associated lignite mine were sufficient to offset increased consumption at natural gas-fired EGUs within the basin, and the consumptive water savings would be equivalent to the water requirements for the hydraulic fracturing of 104 wells in the area, assuming a play median assumption of 4.3 million gallons per well.[4] For the Nueces-Rio Grande river basin, however, net water consumption in the basin increased with lower natural gas prices (Scenario 1) due to increased utilization of natural gas-fired EGUs, and the basin does not have any lignite mines or coal-fired power plants. Thus, it is likely that increased natural gas production and use in the Nueces-Rio Grande basin would lead to increased overall consumption there.

Local water scarcity is an important consideration in determining the impact of changes in consumptive water use patterns in the electricity generation and mining sectors in Texas. It is possible that increasing water consumption for natural gas production in a water-scarce region of Texas while saving water in the power generation sector in a water-rich area of the state could both lead to water savings overall in the state and exacerbation of local water shortages. In addition, increased recycling of produced (flow-back) water from natural gas wells, which has traditionally been small in the Barnett Shale due to the availability of salt water injection wells,[38] could reduce the water footprint of hydraulic fracturing in the state.

ASSOCIATED CONTENT

Supporting Information

Additional text, figures, and tables as noted in the manuscript. This material is available free of charge via the Internet at http://pubs.acs.org.

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The authors declare the following competing financial interest(s): One of the authors (D.T.A.) has research support from a consortium of the Environmental Defense Fund and 11 natural gas producers to measure methane emissions from natural gas production activities. That research is independent of this work.

ACKNOWLEDGMENTS

This material is based upon work supported by the National Science Foundation under Grant No. EFRI-0835414. It also received partial support from the U.S. Department of Energy and the Cynthia and George Mitchell Foundation.

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