3.6 One-mile Grid Map with Areas of Current and Future Focus

3.6.1 Introduction

In this section we analyze the expected increase in industrial power demand as it is projected onto a one-square mile grid (herein defined as block) that overlies a map of the Permian Basin. Here we will be able to see in detail areas where current grid usage is high and where it is most likely to increase over the next 10 years. This process is designed to identify future needs for additional infrastructure in a more detailed, localized way. We will discuss key drivers that are likely to drive the location of future development, display projected power demand in two-year increments and where we see increases over current power usage from current rates through, 2022, 2026 and 2030.

3.6.2 Methodology

GIS tools provided the means whereby this analysis could take place. To create the one-mile grid, we employed the following steps:

1. Created a grid by grouping and merging information pertaining to all horizontal wells (bottom-hole locations) which pertained to each block in the grid. This included average well performance, total cumulative production, total footage drilled, well quality (measured on a scale of 1-5) and well counts.
2. Determined the play assignments of each block by identifying play boundaries, namely the Bone Spring, Spraberry and Wolfcamp plays in the Delaware and Midland Basin, as well as horizontal wells being drilled in legacy conventional plays. Note that some blocks fell within the boundaries of two or more plays, while a large number were located outside all play boundaries
3. Used assumptions pertaining to stacking and spacing to determine the total potential number of well locations that could be drilled in each block, and then subtracted the current location totals in each block from the potential locations in order to obtain the number of remaining locations
4. In conjunction with these location counts in each block we combined the resource quality to assess the current and potential resource in each block and the quality or concentration of that resource. Our assumption is that operators are going to develop better resources first, before developing poorer quality acreage. Using these values and determinations we developed a potential amount of resource that could be developed by 2030.
5. Combined gathering miles in each block with the resource quality and well count to calculate a total factor for each block that was related directly to current and future power usage
6. Grouped or assigned each block to one of the specific 24 counties analyzed in this study and calibrated our models so that the combined block totals in each county would add up to the total of that county. We did this by calibrating all individual block factors (which were calculated by combining resource quality, remaining well count and gathering miles) to the *forecasted county level oil and gas activity demand* for each given year in order to obtain a power usage value for each block.

    Note that for the purpose of this portion of the study forecasted county-level oil and gas activity demand refers to that power required to perform all upstream activities and mid-stream gathering and oil transport *only*. This excludes forecasted power requirements for gas processing and refining, since these activities are either location specific for current or planned processing plants, or we do not know where new ones would be located, even when demonstrating a specific need within a given area or region.

7. This means that the power usage within each block for years 2020, 2022, 2024, 2026, 2028 and 2030 would have to add up to the total for each county, which in turn would have to add up to the total forecasted power demand.

Figure 6-1 provides the correlations between values use in August of each respective year between the Oil and Gas Electricity without Processing and Refinery (MW), which was used to formulate the power distributions shown on the map, and other key comparisons. Within the descriptions of each map, reference is made to yearly values displayed on the graph and highlighted values shown in the corresponding data table.

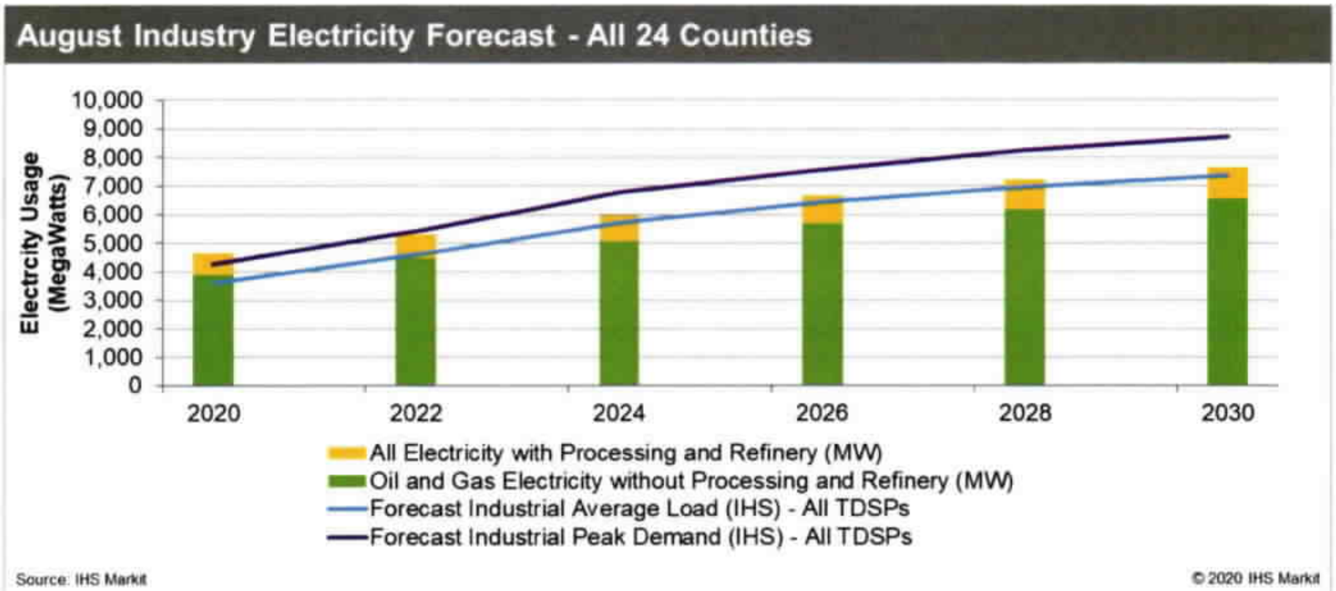


Figure 6-1: August Industry Electricity Forecast for All 24 Counties

Date	Oil and Gas Electricity without Processing and Refinery (MW)	Processing and Refinery (MW)	Total Oil and Gas Electricity Usage (MW)	Forecast Industrial Average Load (IHS) - All TDSPs	Forecast Industrial Peak Demand (IHS) - All TDSPs
Aug-2020	3,888	767	4,654	3,616	4,275
Aug-2022	4,488	826	5,314	4,592	5,429
Aug-2024	5,093	891	5,984	5,730	6,775
Aug-2026	5,709	949	6,658	6,458	7,571
Aug-2028	6,199	1,007	7,206	6,990	8,264
Aug-2030	6,576	1,065	7,640	7,380	8,725

Table 6-1: August Industry Electricity Forecast for All 24 Counties

Figure 6-1 and Table 6-1 show the comparison between total electricity usage of oil and gas activity with/without processing and refinery to the TDSP-served current forecast industrial average load and peak demand. Summing the total for each county sums up to the total forecasted power demand.

Set forth below are the map images used to create the analysis and the results of succeeding years:

3.6.3 Drivers of Power Demand

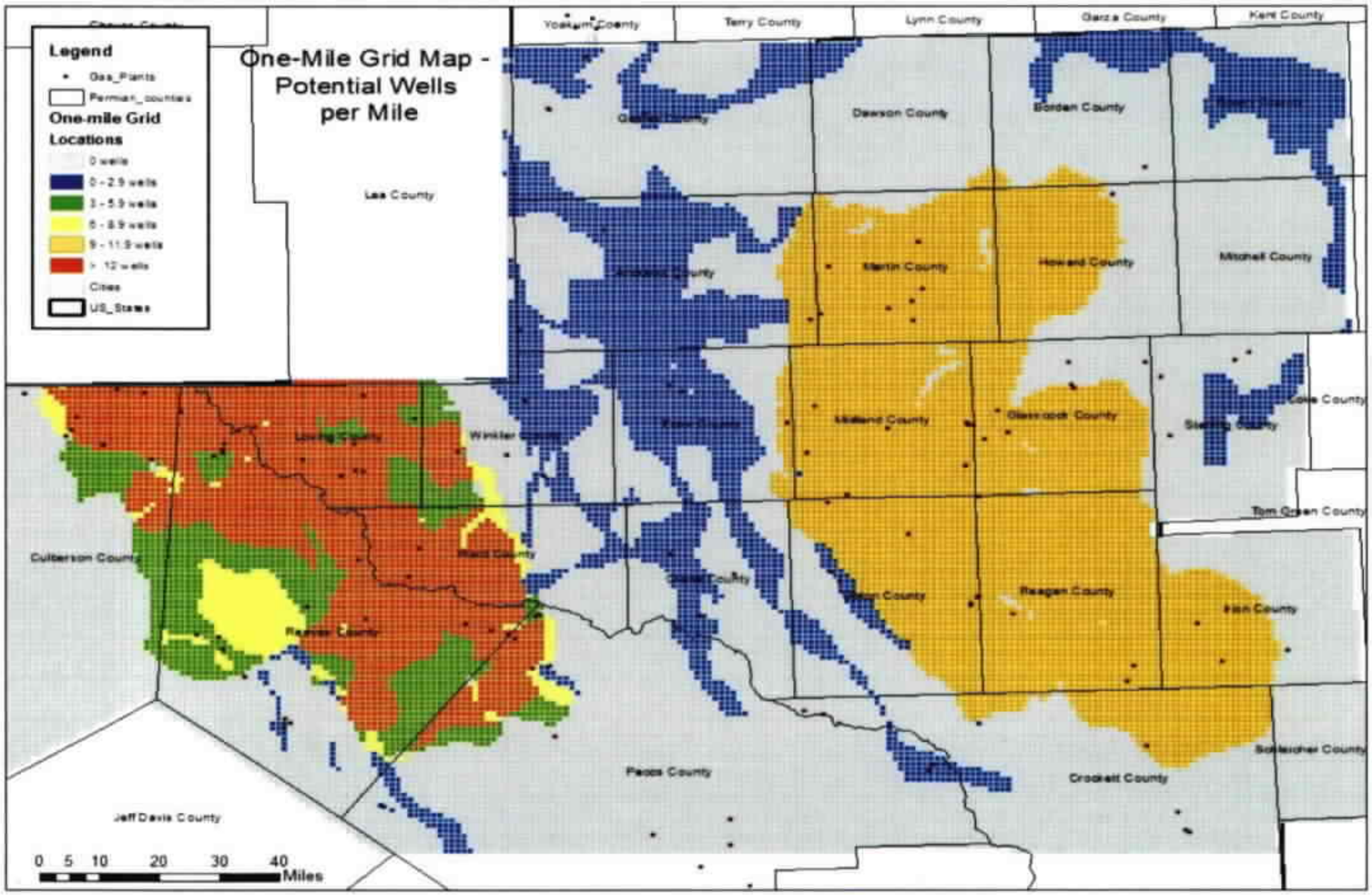


Figure 6-2: One mile grids with potential stacked horizontal well locations per square mile

Figure 6-2 Illustrates potential drilling locations within each block. Horizontal wells have become dominant in the Permian, with over 35,000 potential locations identified. Warmer colors show areas of greater concentration, in terms of one-mile squares. The greatest levels of horizontal well activity have occurred in the Delaware and Midland Basins. The potential wells per block are greater in the Delaware Basin than Midland Basin because there are two plays in the Delaware (Bone Spring and Wolfcamp) with an assumed average of seven stacked reservoirs in these combined plays. On the other hand, we have assumed an average of 5 stacked locations in the Wolfcamp of the Midland Basin. The blue areas typically outline boundaries of conventional plays with horizontal drilling which are less attractive and where we have assumed just one stacked reservoir. We have adjusted these well counts shown on the map to reflect projected lateral lengths (which are longer than the one-mile grid length) and an assumed well spacing of 4 wells per section (side by side in a single block). This means that we expect to see areas where 9 to 12 wells are drilled in a single block.

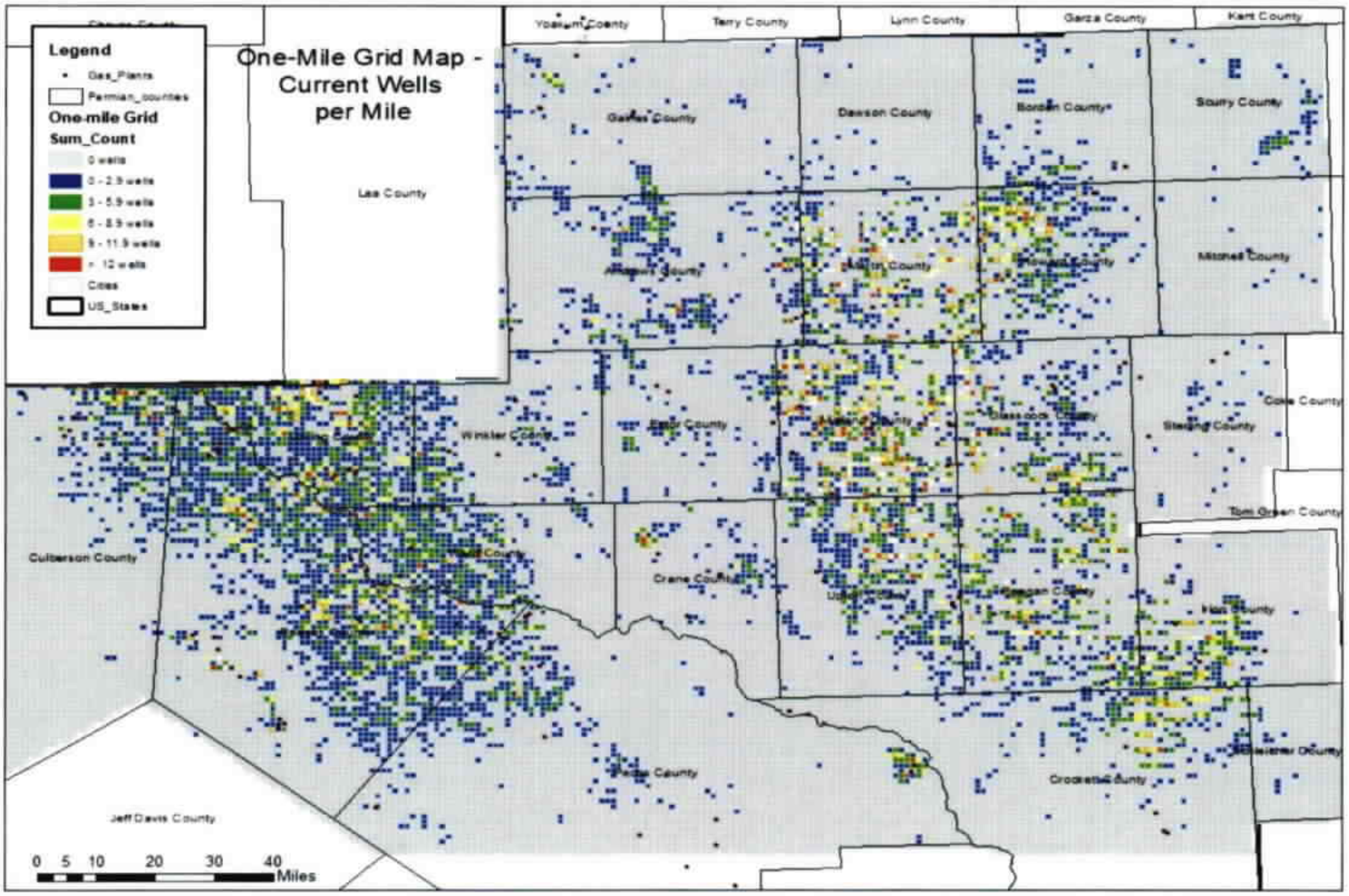


Figure 6-3: One mile grids with current stacked and concentrated horizontal well locations per square mile

Figure 6-3 illustrates locations within each block that have already been drilled. Generally, most blocks have less than 6 wells drilled in each with a few containing more. The Midland Basin concentrations as shown by the preponderance of yellow blocks appears to be somewhat more developed.

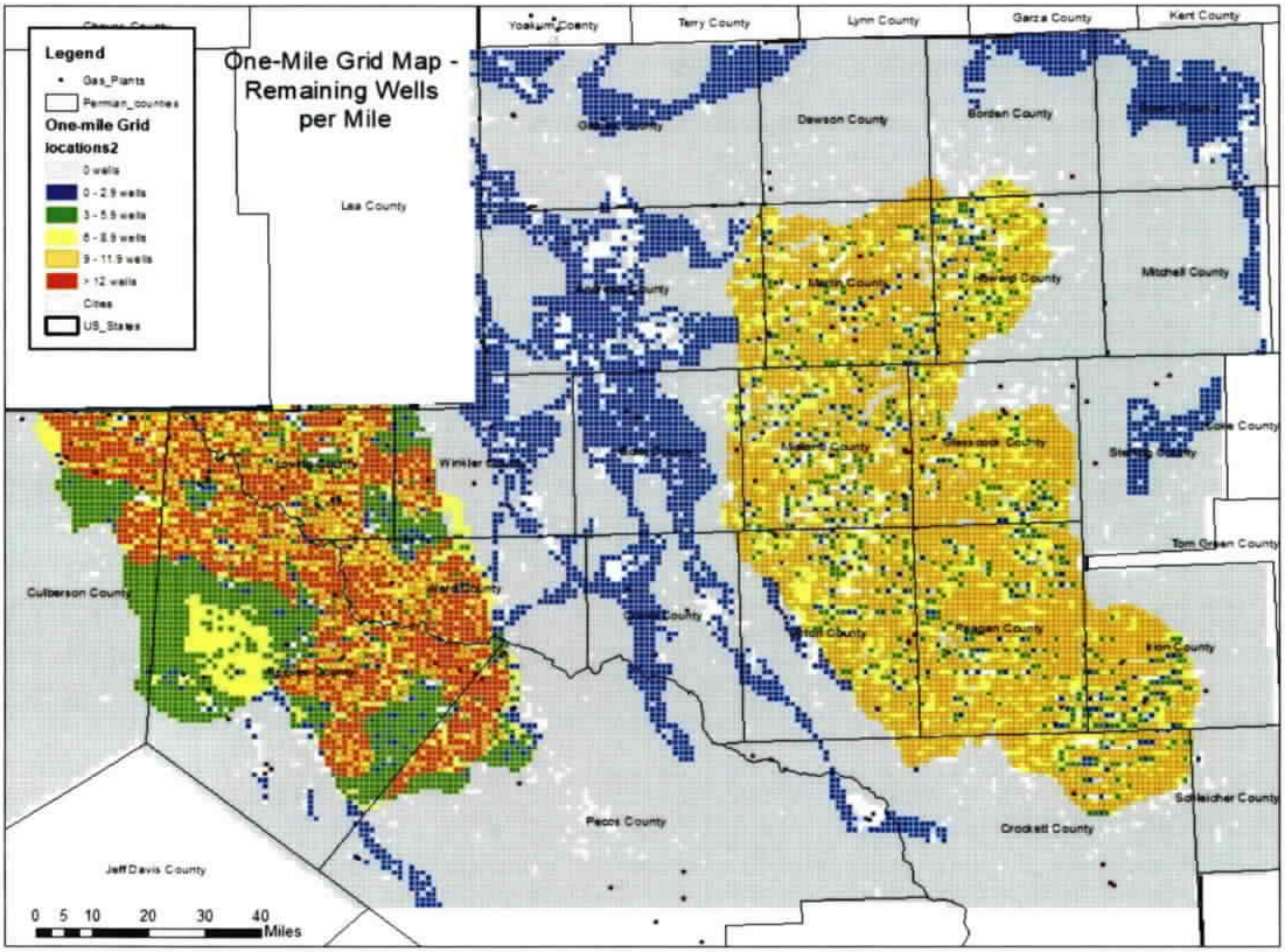


Figure 6-4: One mile grids with remaining stacked and concentrated horizontal well locations per square mile

Figure 6-4 illustrates potential remaining drilling locations within each block. These values were obtained by subtracting the total wells drilled in each block from the potential wells drilled in each block. Note that there are still many blocks that are yet undrilled but are located in the play fairways and where we expect development to occur.

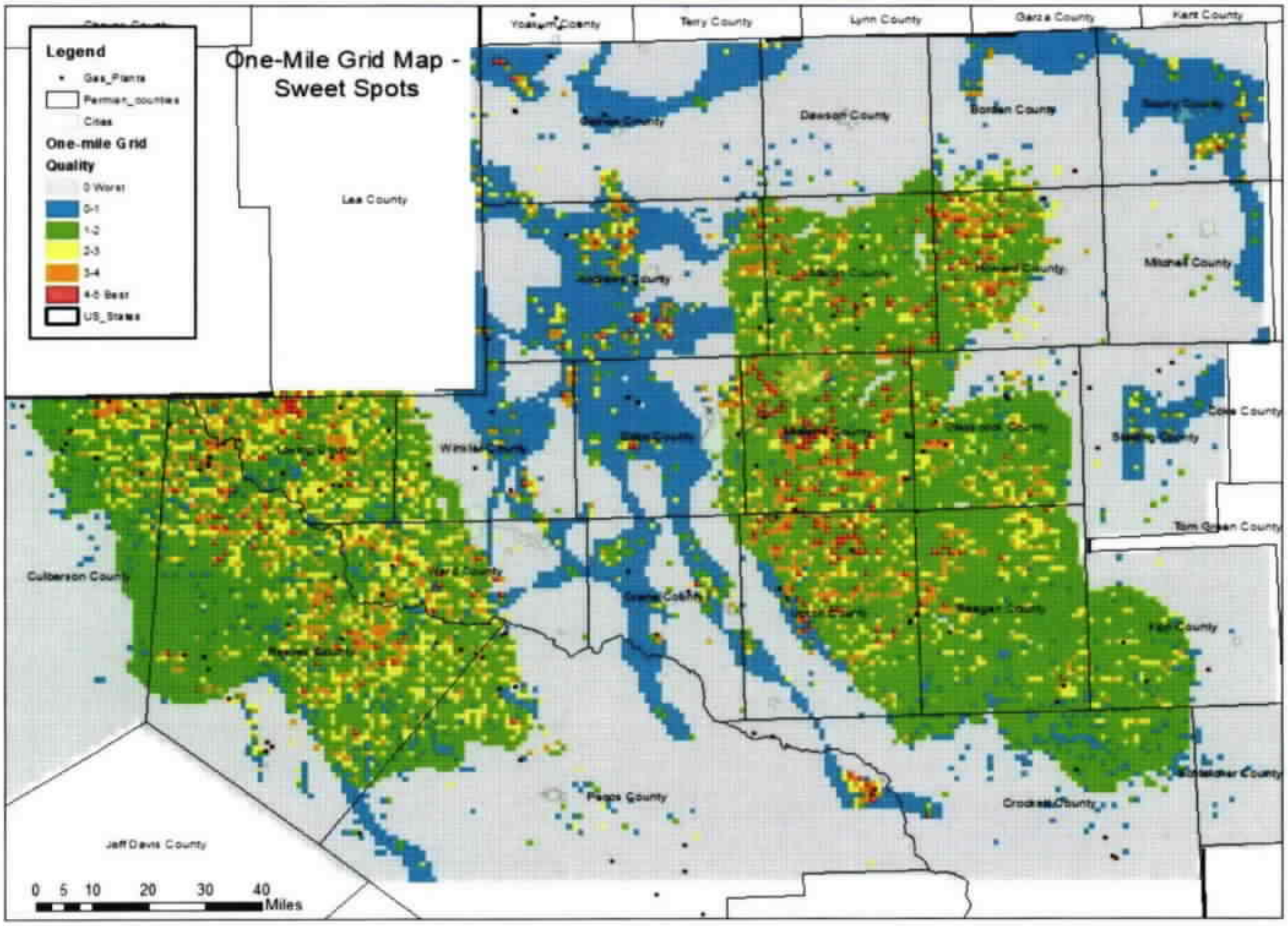


Figure 6-5: One mile grids with average well quality

Figure 6-5 illustrates the quality of each block. IHS Markit tracks the performance of wells. Based on this well performance, IHS Markit ranks acreage into five quality categories. On the map, 0 shows areas that are not generally prospective (in gray), while 4-5 are rated the best (in red). Historical well performance drives these ratings with the best wells indicating the best rated acreage. The best acreage is often referred to as the sweet spot or core of the play. Operators are more likely to drill in these "sweet spots" shown in warmer colors in the future and will develop them first. The blue areas are signifying more conventional activity with higher water-oil ratios than unconventional wells, which will result in higher power demand for water production and disposal.

Current power demand will tend to be focused in the yellow to red blocks, but in the future will migrate to the green blocks as these somewhat less prospective areas get developed.

3.6.4 Forecasted power demand by block

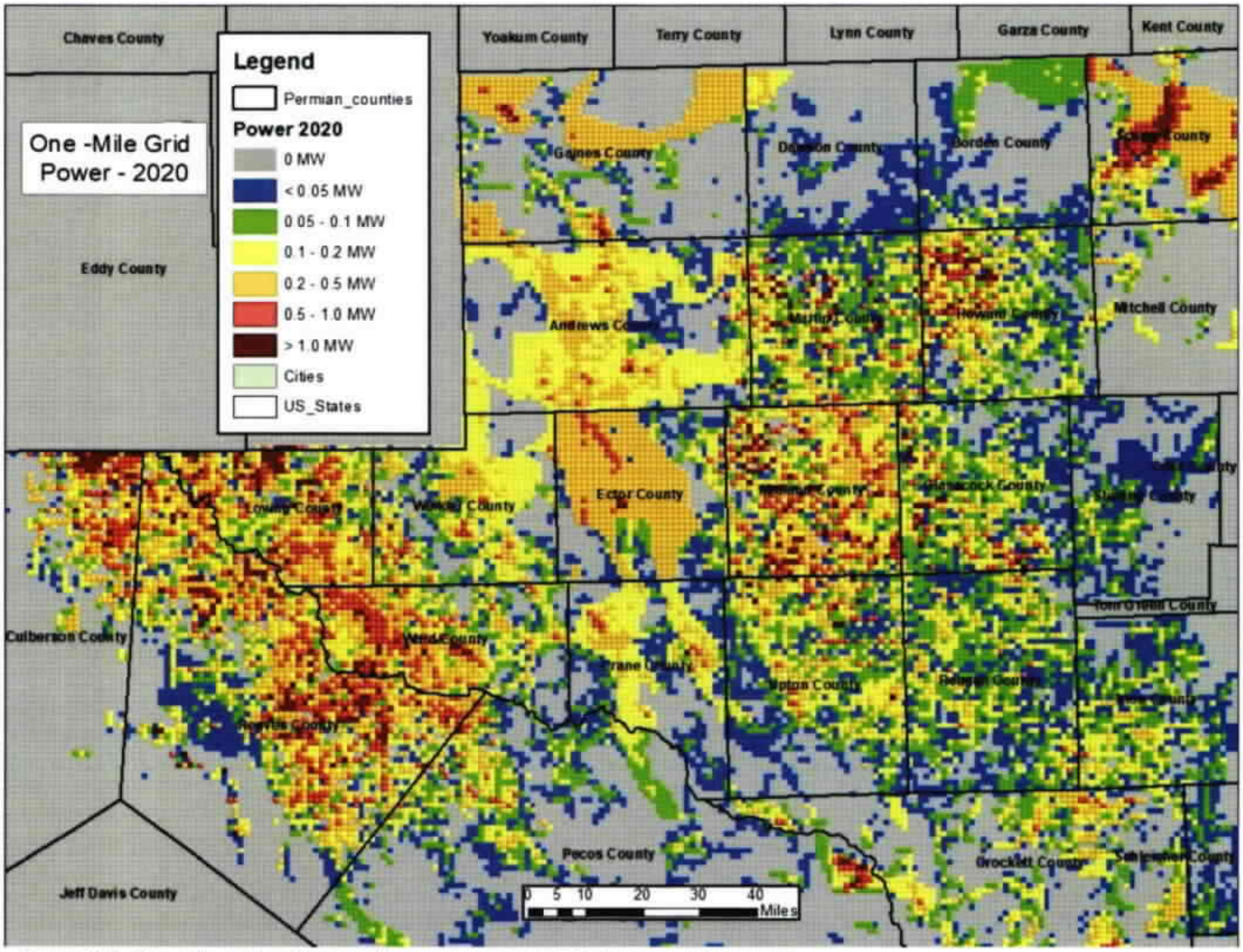


Figure 6-6: One mile grids with current power demand (MW) for each grid square

Figure 6-6 illustrates current power demand within each block. Power demand in 2020 is expected to be concentrated in the unconventional areas of the Delaware and Midland. There are some scattered pockets of high demand, even in conventional areas where oil field production is still occurring. The total power demand for oil and gas activities (without processing and refining) for 2020 is projected to be 3,888 MW, which is scattered throughout the basin in various concentrations as you see on the map. This compares with a total August 2020 industrial power demand of 4,654 MW with forecasted peak demand of 4,275 MW (note that for this year the total demand that can be supplied by TDSPs is lower than the industrial demand).

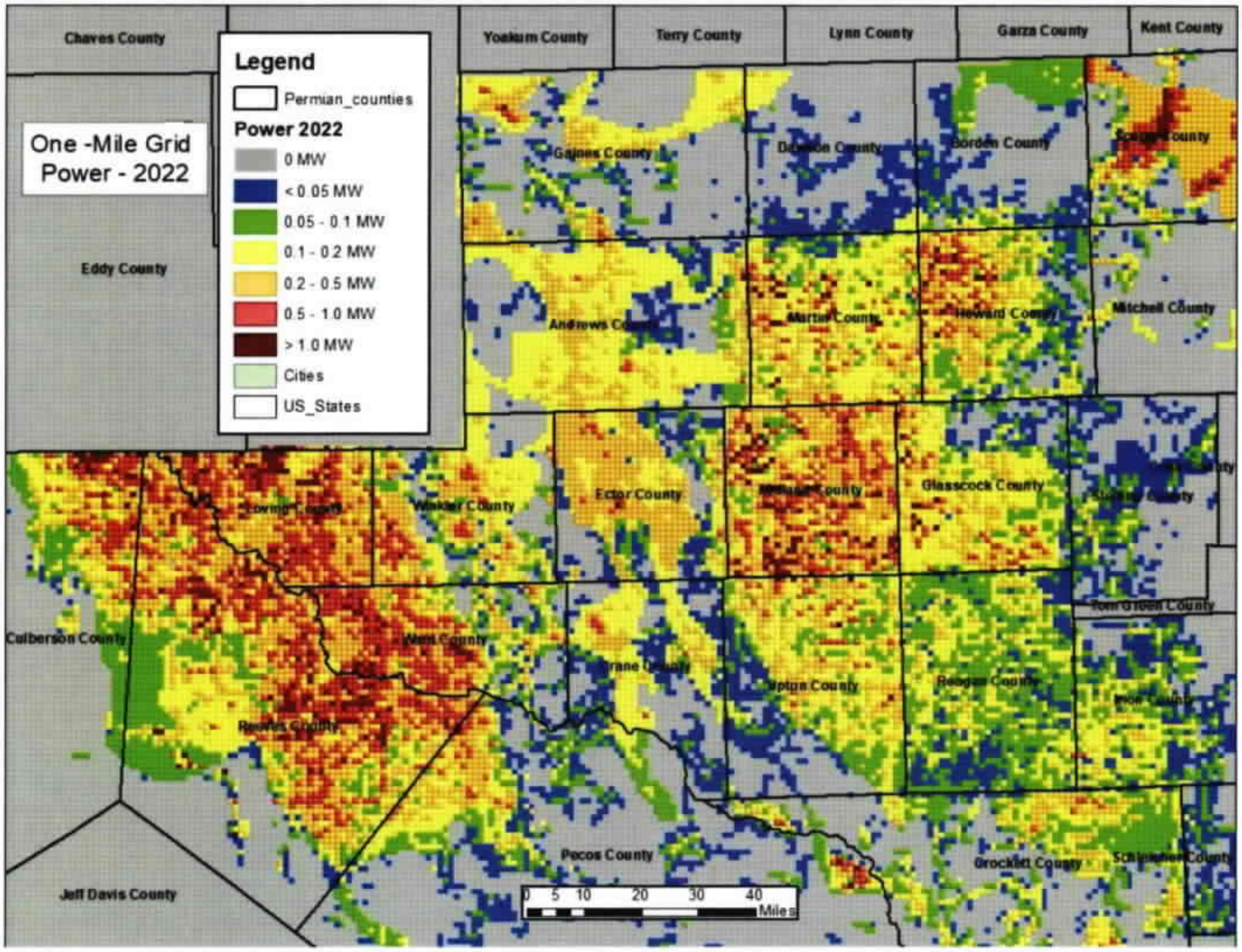


Figure 6-7: One mile grids with forecasted power demand (MW) in 2022 for each grid square

Figure 6-7 illustrates power demand within each block in 2022. By 2022, greater power demands are more widespread in the areas with more unconventional activity. Many of the blocks in the Delaware and Midland Basins are expected to require over 1 MW. Scattered pockets of high demand, even in conventional areas persist. The total power demand for oil and gas activities (without processing and refining) for 2022 is projected to be 4,488 MW, which is scattered throughout the basin in various concentrations as you see on the map. This compares with a total August 2022 industrial power demand of 5,314 MW with forecasted peak demand of 5,429 MW.

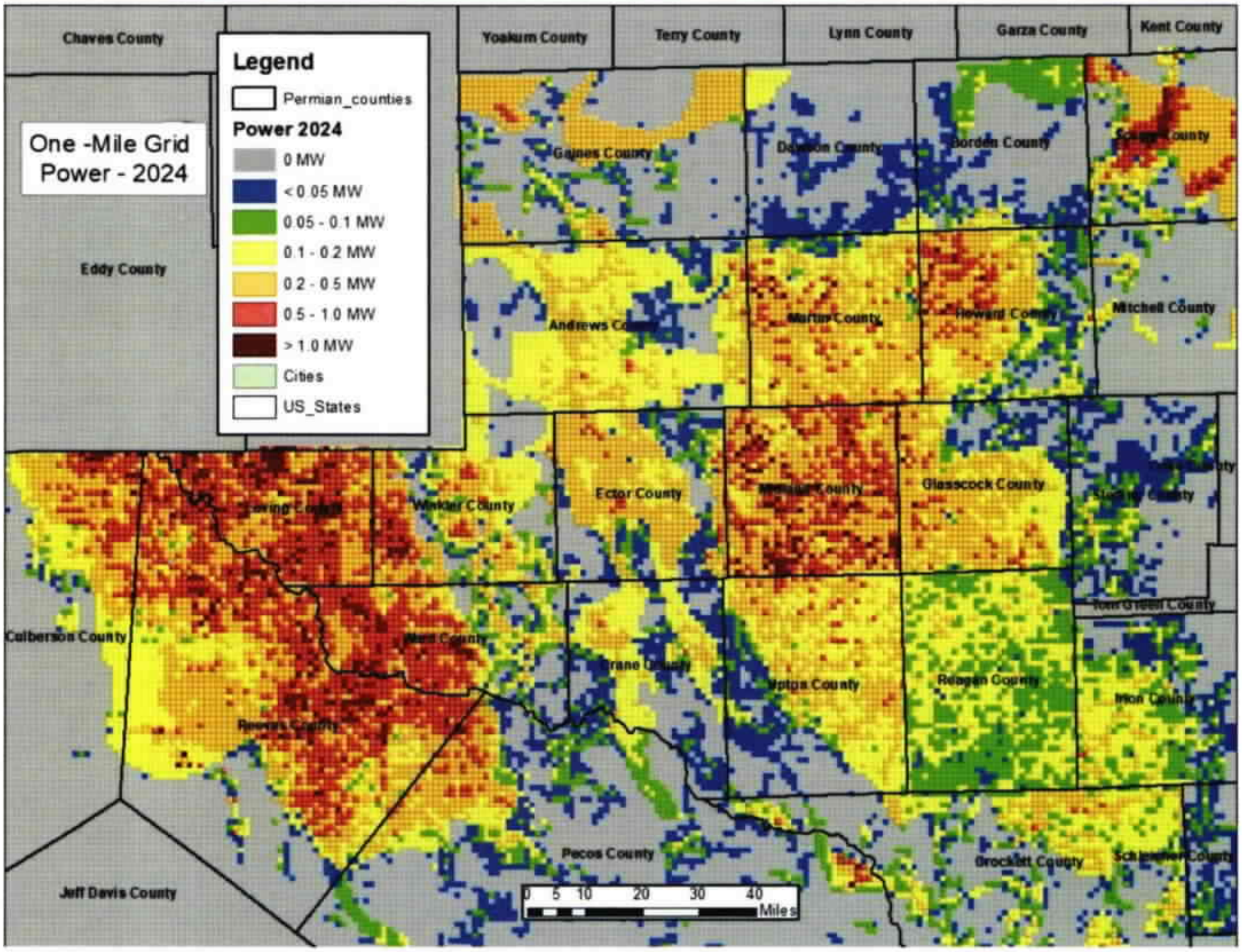


Figure 6-8: One mile grids with forecasted power demand (MW) in 2024 for each grid square

Figure 6-8 illustrates power demand within each block in 2024. By 2024, greater power demands are more widespread in the Delaware Basin, with power demand being concentrated in Midland County of the Midland Basin where production is expected to grow rapidly during this period. This will spill over into the east end of Ector County where the trend continues. The total power demand for oil and gas activities (without processing and refining) for 2024 is projected to be 5,093 MW, which is scattered throughout the basin in various concentrations as you see on the map. This compares with a total August 2024 industrial power demand of 5,984 MW with forecasted peak demand of 6,775 MW.

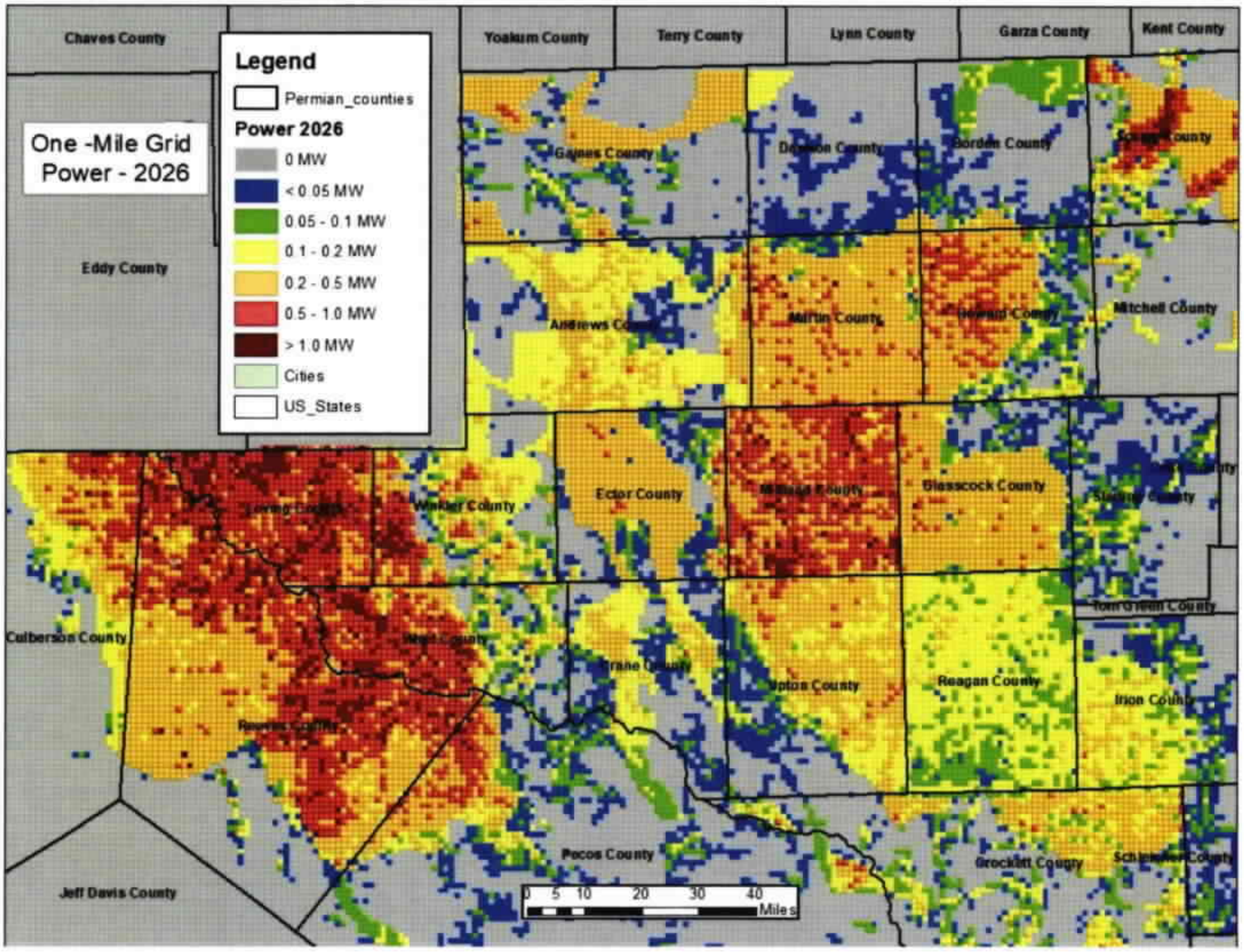


Figure 6-9: One mile grids with forecasted power demand (MW) in 2026 for each grid square

Figure 6-9 illustrates power demand within each block in 2026. By that year, greater power demands are more widespread in the Delaware Basin with some areas, such as Winkler County, becoming more concentrated. Power demand continues to be concentrated in Midland and east Ector County where development is intense. The total power demand for oil and gas activities (without processing and refining) for this year is projected to be 5,709 MW, which is scattered throughout the basin in various concentrations as you see on the map. This compares with a total August 2026 industrial power demand of 6,658 MW with forecasted peak demand of 7,571 MW.

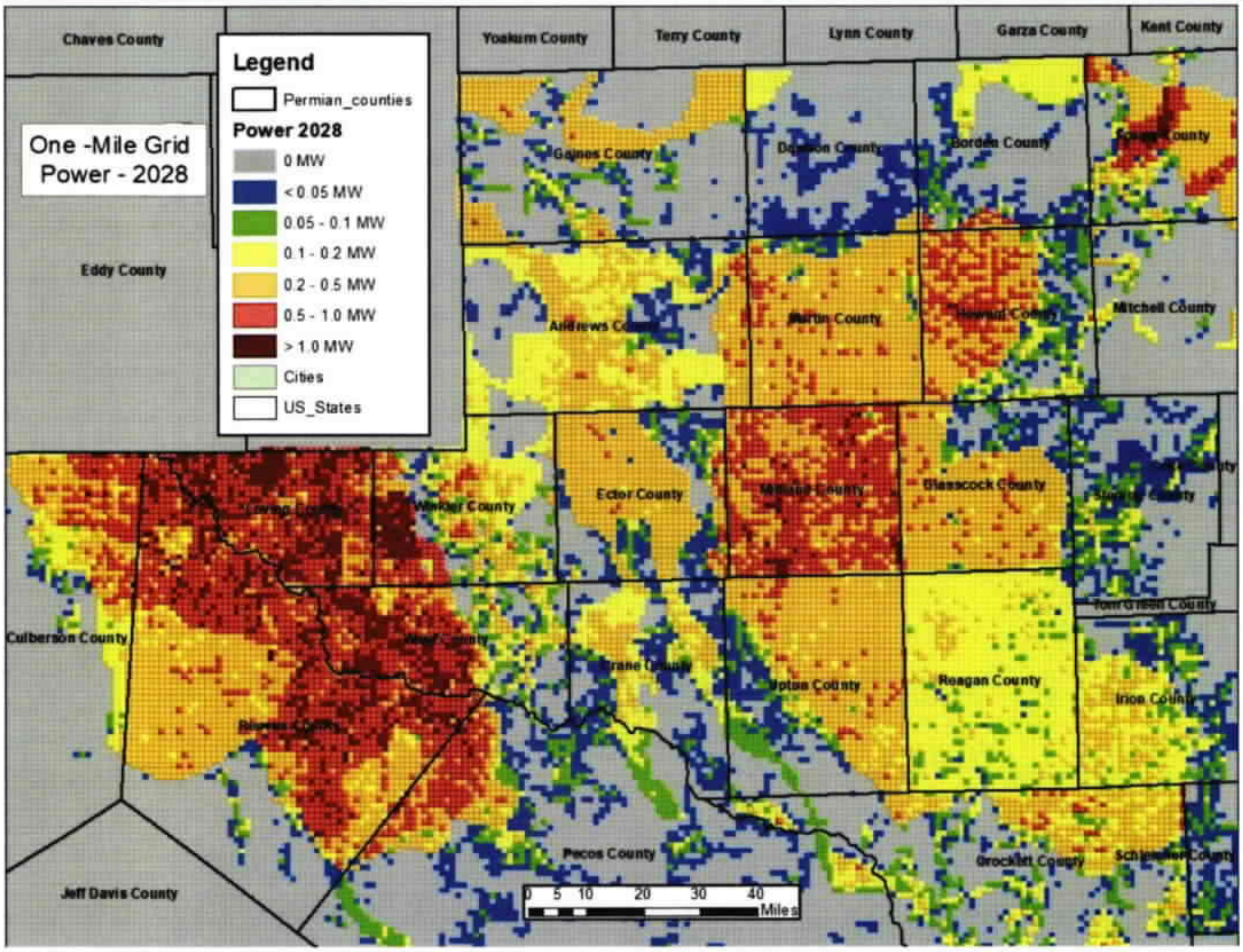


Figure 6-10: One mile grids with forecasted power demand (MW) in 2028 for each grid square

Figure 6-10 illustrates power demand within each block in 2028. By that year, greater power demands are found in similar locations as they were in 2026, but they are more intense. Howard County is beginning to emerge as a power demand center in the Midland Basin. The allocating of power to blocks by county power totals is apparent in the Midland Basin, as you see some counties with heavier concentrations of power than others. The total power demand for oil and gas activities (without processing and refining) for 2028 is projected to be 6,199 MW, which is scattered throughout the basin in various concentrations as you see on the map. This compares with a total August 2028 industrial power demand of 7,206 MW with forecasted peak demand of 8,264 MW.

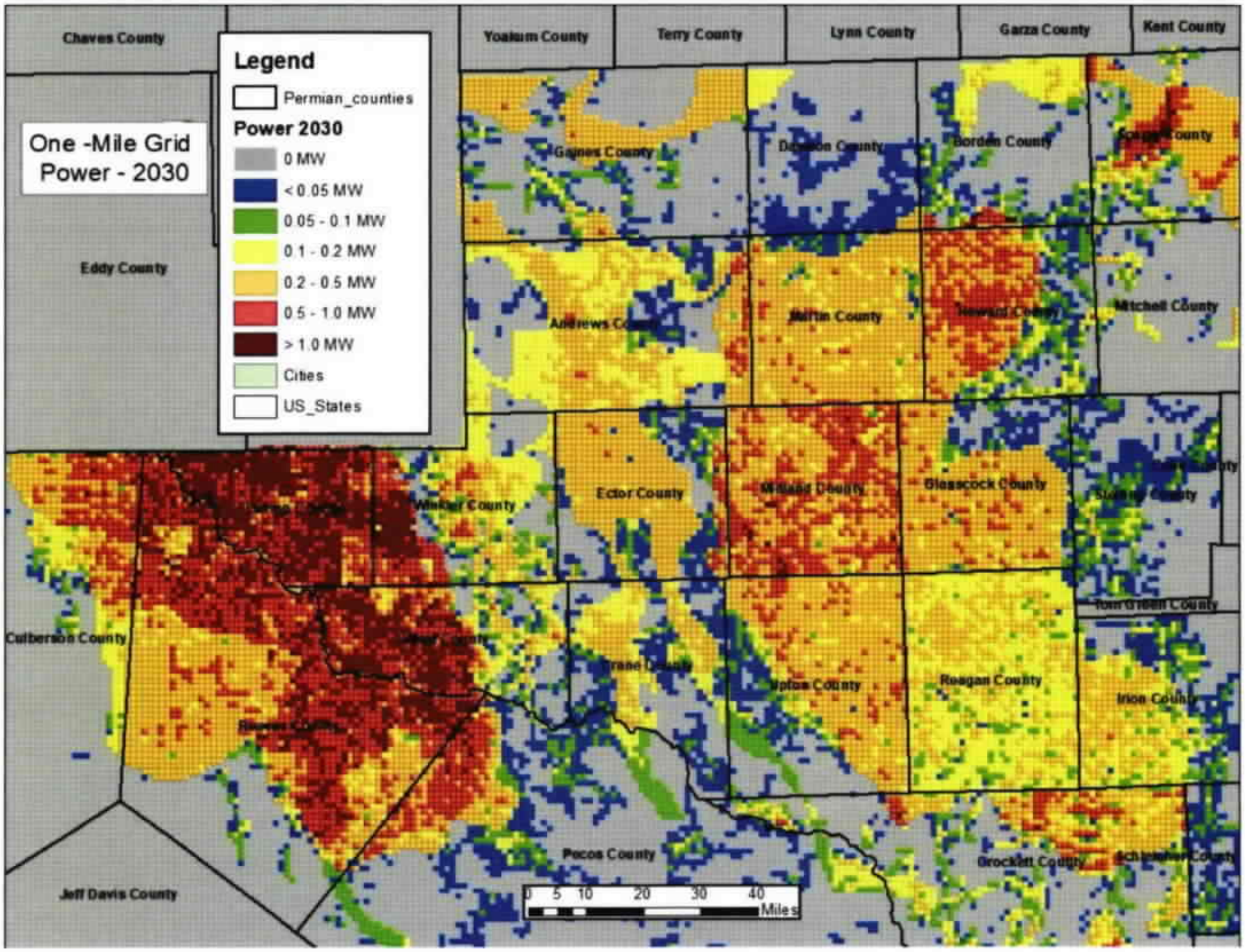


Figure 6-11: One mile grids with forecasted power demand (MW) in 2030 for each grid square

Figure 6-11 illustrates power demand within each block in 2030. By 2030, greater power demands are found in similar locations as they were in 2028 but they continue to intensify. In other words, the patterns and trends of 2028 are similar, but more concentrated. The allocating of power to blocks by county power totals is still apparent in the Midland Basin, although you are beginning to see some more concentrated development in Reagan County and less in Midland County as production declines in that county. The total power demand for oil and gas activities (without processing and refining) for this year is projected to be 6,576 MW, which is scattered throughout the basin in various concentrations as you see on the map. This compares with a total August 2030 industrial power demand of 7,640 MW with forecasted peak demand of 8,725 MW.

3.6.5 Relative Changes in Power from Current Levels

This analysis is a useful tool that can inform the power planning process, but not necessarily determine final outcomes. The analysis is based primarily on showing where oil and gas development is most likely to occur and to how intense that development will be. Other studies performed by IHS Markit suggest that the unconventional development within the Permian Basin unconventional plays is less than 20%, which suggests that a considerable amount of power requirement lie ahead and that the results of this analysis will assist in determining where that remaining 80% of development is likely to take place.

Figure 6-12 illustrates the change in power demand within each block from 2020 to 2022. From 2020 to 2022, much of the power increase is expected to be in the Delaware Basin (especially in western Winkler County). Midland County is expected to show the greatest increases in the Midland Basin. Certain conventional areas with increased water cut also are expected to increase somewhat, most notably Scurry County. Between 2020 and 2022, power demand is expected to increase by 872 MW (upstream, gathering and oil transport).

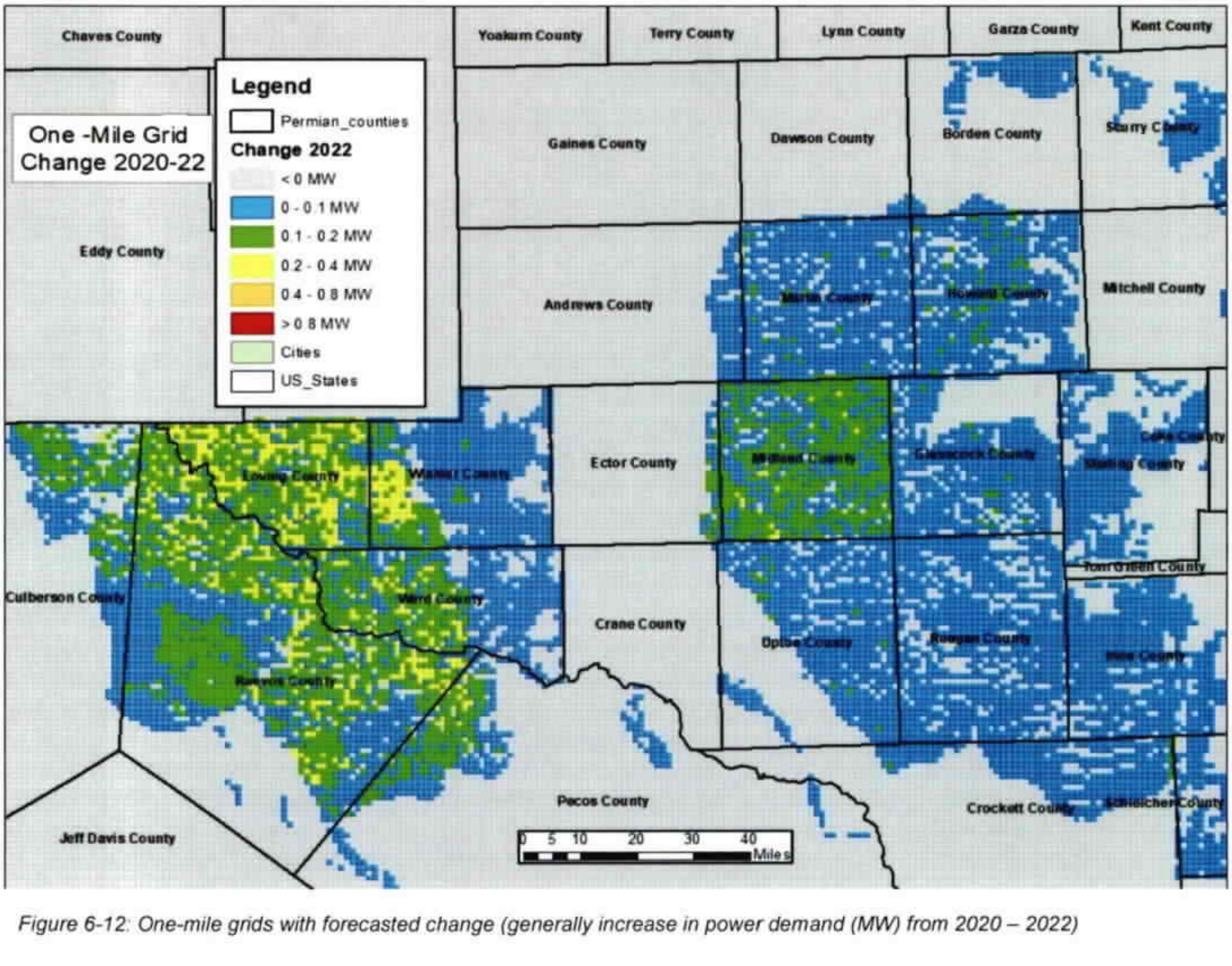


Figure 6-12: One-mile grids with forecasted change (generally increase in power demand (MW) from 2020 – 2022)

Figure 6-13 illustrates the change in power demand within each block from 2020 to 2026. From 2020 to 2026, the largest power increases are still expected to be in the Delaware Basin. Larger changes in the Midland Basin are expected in Martin and Glasscock Counties, rather than in Midland County. Certain conventional areas with increased water cut also are expected to increase, notably Scurry County. The concentrated changes in east Ector and Andrews counties are because of effects caused by the unconventional plays occupying a very small portion of these counties and the power increases attributable to these counties being concentrated primarily in these confined locations. Between 2020 and 2026, power demand is expected to increase by 2,226 MW (upstream, gathering and oil transport).

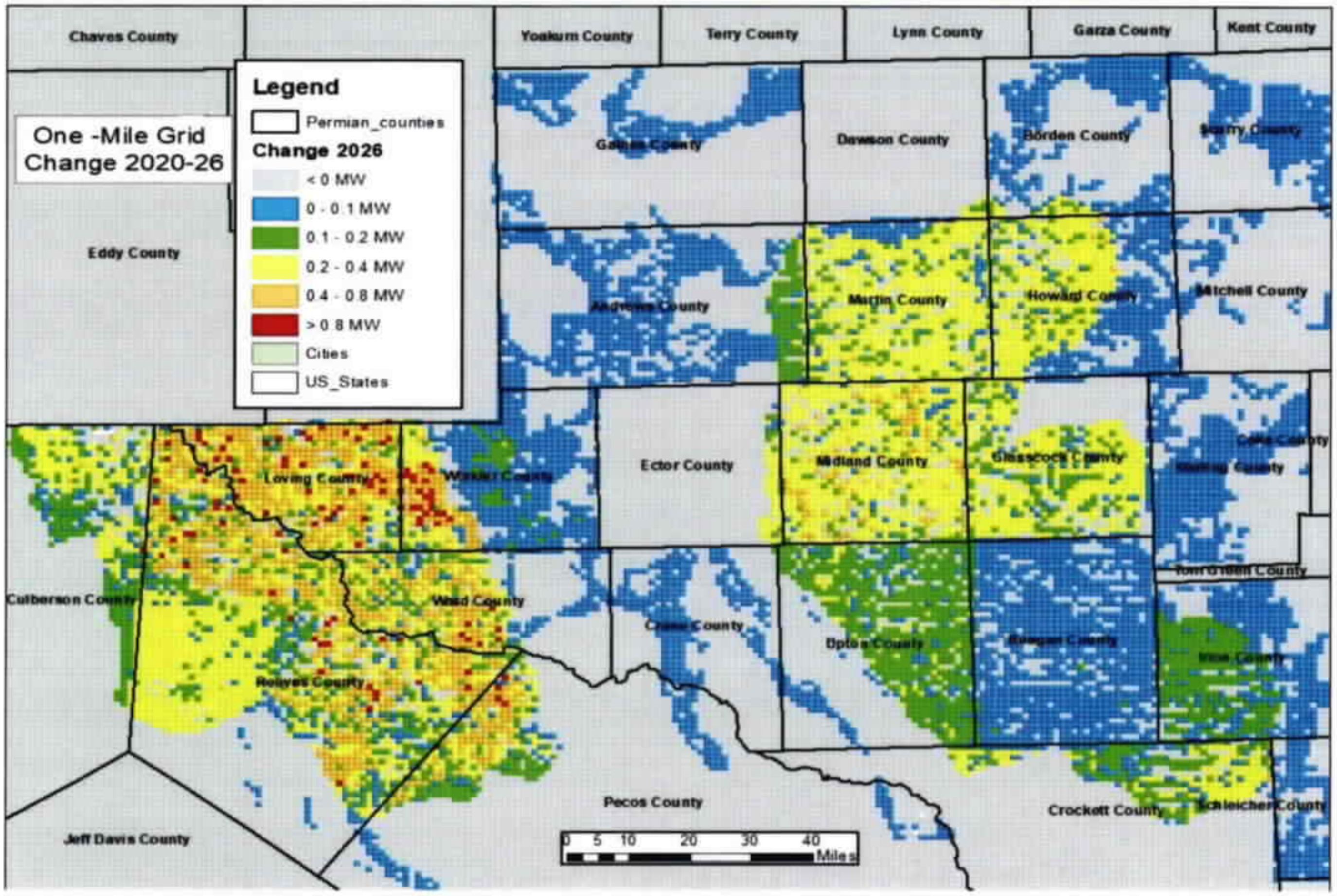


Figure 6-13: One-mile grids with forecasted change (generally increase in power demand (MW) from 2020 - 2026

Figure 6-14 illustrates the change in power demand within each block from 2020 to 2030. From 2020 to 2030, the largest power increases are expected to be in the Delaware Basin. Larger changes in the Midland Basin are expected in in Howard County with some meaningful increases are also expected in Upton County. The east Ector and Andrews county issue discussed earlier will also show up here as well. Between 2020 and 2030, power demand is expected to increase by 3,260 MW (upstream, gathering and oil transport).

To conclude Part 3, IHS Markit will recap the successful completion of the goals of this section, as IHS Markit has been able to (1) validate the calculated power usage against real historical data, (2) determine the extent to which oil and gas operations are on the electrical grid within each of the counties, (3) build a power demand forecast at the county level by applying these comparisons, (4) apply appropriate load factors to calculate peak coincidence, and (5) integrate these county-level power forecast with current and projected oil and gas activities, including projected drilling to identify areas where the highest likelihood of increased demand is likely to occur.

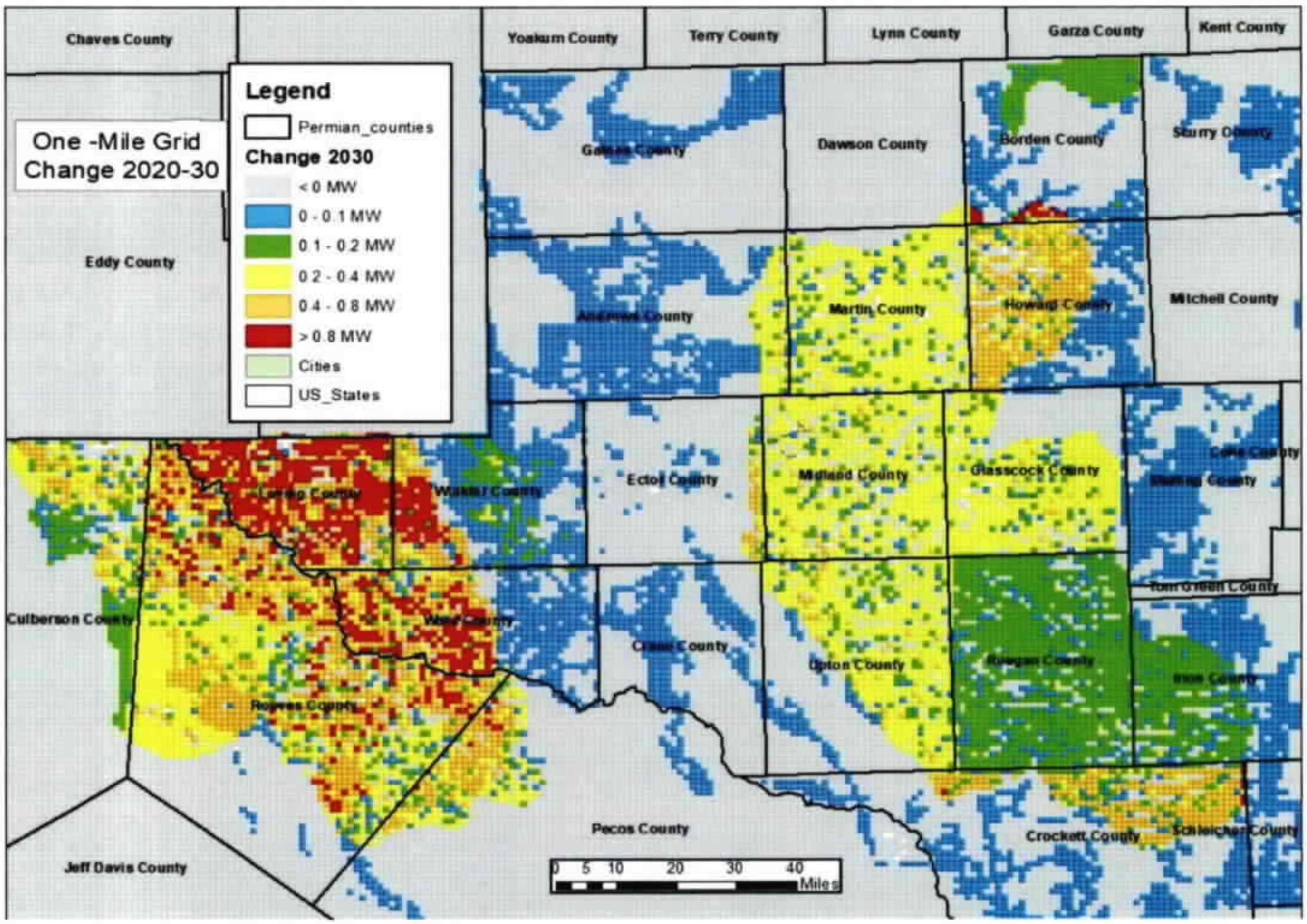


Figure 6-14: One-mile grids with forecasted change (generally increase in power demand (MW) from 2020 - 2030

4 Permian Basin Total Power Demand Forecast

4.1 Introduction

In the previous section, we progressed through the steps of analyzing and comparing historical oil and gas activity power demand with historical average power usage in order to lay the foundation for creating a forecast of future power demand. Furthermore, we determined a forecast for peak load. This was done solely for industrial load, and while industrial load will account for the vast majority of future load expectancy, we need to include residential and commercial load forecast in order to provide a complete picture of future load demand. In this part 4, we will provide a methodology and determine an outlook for future residential and commercial load and combine this outlook with the industrial load outlook to create a total load forecast. When creating this combined outlook, we will describe some adjustments needed in order to account for coincidence when combining the two outlooks. This combined outlook will be presented for each of the four regions and for the Permian Basin.

Findings

- The Delaware Basin's power demand is completely dominated by the industrial sector where oil and gas activity is expected to substantially increase. Growth is expected within the residential and commercial sectors, but it will constitute a small fraction of the power forecast in the Delaware Basin. Peak power for all sectors is expected to increase by 294% from 1,300 MW at the 2019 peak to 4,900 MW at the 2030 peak.

- The Midland Basin's power demand has a large contribution from residential and commercial activity, but the industrial sector accounts for the majority of the existing load. Since the growth rate in the industrial sector will be higher, the residential and commercial power will become a smaller percentage of the total load served over the next decade. Peak power for all sectors is expected to increase by over 56% from just over 2,040 MW at the 2019 peak to nearly 3,200 MW at the 2030 peak.

- The Central Basin Platform's power demand has a substantial contribution from residential and commercial activity much like the Midland Basin. However, residential and commercial power will become even more important over the next decade as the oil and gas activity stagnates in this region. Peak power for all sectors is expected to increase by 10% from 1,250 MW at the 2019 peak to just 1,370 MW by the 2030 peak.

- Power demand in the Fringe area of the Permian Basin currently has only a minor contribution from residential and commercial activity, which is expected to remain relatively constant throughout the study. Most of the Fringe area's growth will come from the industrial sector, but growth will be limited since oil and gas activity is not expected to ramp up much over the next decade. Peak power for all sectors is expected to increase by only 24% from 570 MW at the 2019 peak to 710 MW at the 2030 peak.

- Overall, the Permian region's power demand is dominated by the industrial sector where most of the growth is expected. Still, power demand is expected to grow in all sectors. Peak power for all sectors is expected to almost double from just under 5,200 MW at the 2019 peak to nearly 10,200 MW at the 2030 peak.

4.2 Residential and Commercial Power Demand

4.2.1 Input data

Residential and commercial power demand is expected to be a smaller component of the growth story in West Texas. IHS Markit obtained several data sets to feed into the residential and commercial demand forecast, which we approach as a granular econometric analysis. The input data sets are summarized in Table 2-1.

Data	Period	Frequency	Granularity	Source
Electricity usage billing data, with and without Sharyland, aggregated by county and customer type (Industrial, Commercial and Residential)	Jan 2010 - Dec 2019	Monthly	County level	Oncor
15-minute interval load data, aggregated by county and customer type (Industrial, Commercial and Residential)	Jan 2018 - Nov 2019	15-minute intervals	County level	Oncor
Oncor load serving ratio (estimated)	2019	Annual	County level	Oncor
Gross county product history and outlook	2010 - 2030	Annual	County level	Bureau of Economic Analysis (BEA) for history; IHS Markit for outlook
Average household income history and outlook	2010 - 2030	Annual	County level	Bureau of Economic Analysis (BEA) for history; IHS Markit for outlook
Household formation history and outlook	2010 - 2030	Annual	County level	Bureau of Economic Analysis (BEA) for history; IHS Markit for outlook
Residential and commercial electricity retail price history and estimated outlook	2010 - 2030	Annual	State level	Energy Information Administration (EIA) for history; IHS Markit for outlook
Heating degree days and cooling degree days	Jan 2010 – Nov 2019	Monthly	Metropolitan level	National Oceanic and Atmospheric Administration (NOAA)

Table 2-1 Input data sets to the residential and commercial power demand analysis

We aligned and compared the monthly electricity billing data with the 15-minute interval power data. Figures 2-1 and 2-2 provide examples of the comparison for Ector County for the residential and commercial sectors. In most counties, the two sets aligned well with some time lag because the billing data inherently contain a lag. An exact adjustment is not feasible as a practical matter because customers experience varied lags and the time resolution of the billing data is monthly. We made the simple adjustment to slide the billing data back one month (e.g., September billing data was assumed to apply to August). The observed alignment made us comfortable using the billing data for the econometric analysis on an annual basis and derive monthly load apportionments, and also comfortable using the 15-minute interval data for superimposing a load profile onto the results (e.g., calculating and applying monthly load factors to derive peak demand estimates). The 15-minute data do not require the time shift.

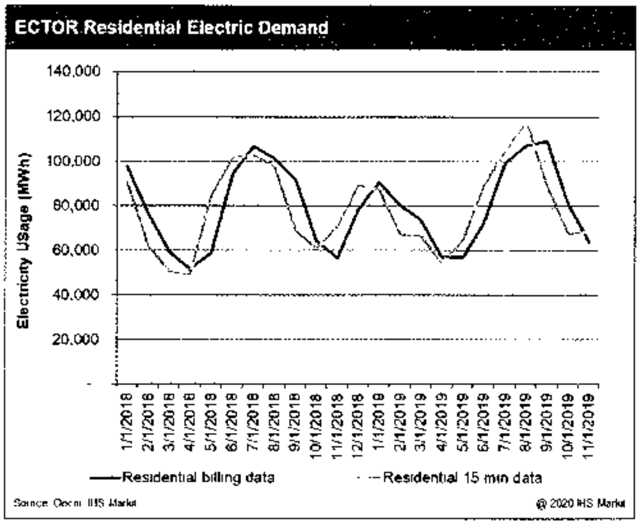


Figure 2-1 Comparison of billing data and 15-minute interval data for Ector County, residential sector

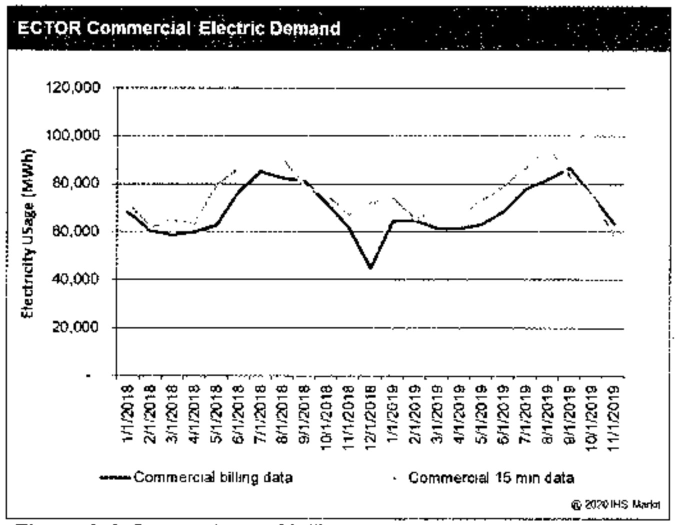


Figure 2-2 Comparison of billing data and 15-minute interval data for Ector County, commercial sector

4.2.1.1 Data challenges

IHS Markit encountered some challenges with the data we obtained. We adjusted and made estimations to clean up the data sets. These are important steps we took to gain confidence in the overall electricity demand forecasts:

- Sharyland adjustment: Oncor acquired Sharyland Utilities' retail distribution operations in late 2017. This transaction resulted in a large increase in electricity sales from 2018 onward in counties formerly served by Sharyland. These counties include Borden, Glasscock, Howard, Martin, Midland, Mitchell, Reagan, Sterling, and Upton. In order to derive a consistent history of demand, a scale-up analysis was performed in these counties to adjust the history of electricity sales before 2018 "as if" they included Sharyland. The analysis is informed by Oncor's provided electricity sales data (billing data) with and without the Sharyland acquisition. Sharyland's share of demand is inferred and applied to the history to scale up the historical demand. In cases (Borden and Sterling) where there are missing billing data without Sharyland, we assume that the increase in demand from 2017 to 2018 is largely due to Sharyland's acquisition. We then use this estimated ratio to adjust the history.

- Limited historical data set: Ten years (2010 to 2019) of electricity usage billing data are available for the residential and commercial demand forecast. We used these data to feed into our econometric analysis. To allow us to forecast peak demand, monthly load factors in each county for both sectors were calculated based upon 23 months (Jan 2018 – Nov 2019) of 15-minute interval power data. In some cases where there are missing power data (Borden and Irion) in 2018, only the most recent one-year history was used.

- Inconsistency in classification: We are comfortable with the overall alignment of the billing data and 15-minute interval data. However, there are some consumer class level mismatches in some counties. We adjusted the commercial sector load factors in these counties by apportioning out the average amount of load from industrial sector, thereby making the best estimate of commercial load factor that we could.

- Missing data: IHS Markit did not receive residential and commercial electricity billing data for Crockett and Schleicher counties since Oncor does not serve this area. Therefore, these two counties' residential and commercial demands are not forecasted. Load factors in the adjacent major counties are used as proxies.

- Several of the counties evaluated have small average loads (less than 4MW). To address this challenge, the adjacent major counties that are serving the load are used as a proxy in our analysis. We use the adjacent county's demand growth rate to approximate the demand growth rate in the county with small load. The small load proxies are summarized in Table 2-2.

Counties	**Serving entity**
Irion: small average load	Load served from Reagan County Substation.
Sterling: small average load	Load served from Reagan County Substation and small amount from Mitchell County Substation.
Gaines: small average load	Load served from Andrews County substation

Table 2-2 Use of proxy counties to address small average load counties

4.2.2 Methodology for residential energy and peak demand forecasts

We forecasted annual residential demand by county. The explanatory variables in our residential analysis are summarized in Table 2-3.

Explanatory variables	**Note**
Residential electricity sales price (res_price)	We use the IHS Markit November 2019 ERCOT wholesale power price forecast, with estimated conversion to a residential retail price. The growth rate (estimated at 1.8 percent) from 2019 to 2030 is then used to create a smooth trajectory of retail prices so that the longer-term retail price trend is captured in the econometric equations without distorting month-to-month patterns in power consumption in our forecast. Historical retail prices are taken from the US Energy Information Administration (EIA).
Average household income (ahi)	IHS Markit macroeconomics outlook for West Texas. Historical data taken from Bureau of Economic Analysis (BEA).
Household formation (HH)	
Cooling degree days/Heating degree days (CDD/HDD)	We use Midland metropolitan numbers from NOAA as history and 10-year average for the forecast. Our forecast assumes that the most recent 10-years of weather data are "weather normal."

Table 2-3. Explanatory variables in the residential electricity demand forecast

The following is the general econometric equation that we used in the residential sector:

$$\log(\text{res\_demand\_county}/\text{HH\_county}) = \beta_1 \log(\text{res\_price}) + \beta_2 \log(\text{ahi\_county}) + \beta_3 \log(\text{CDD}) + \beta_4 \log(\text{HDD}) + \text{Constant}$$

We add a time trend variable and a lag (1 year) left-hand side variable when the residuals are serially correlated to correct the regression (and restore the basic assumptions of linear regression). In the small load counties (Sterling, Gaines, and Irion as discussed above), we use the adjacent county's demand growth rate to approximate their demand growth rate.

After forecasting residential demand for each county using forecasts of the explanatory variables (and household formation, which appears on the left-hand side of our regression equation), we take the following additional steps:

- Disaggregate annual energy demand to monthly energy demand using the average monthly fraction inferred from the electricity billing data.
- Adjust the results for a 4% distribution loss factor for residential / commercial demand. This "grosses up" the sales-level data to the distribution substation level. Accordingly, we divide the monthly energy forecasts by 0.96.
- Convert monthly energy demand to annual peak demand by county: We use the 15-minute interval data to calculate residential load factors for each county in each month. The load factor is applied to the monthly energy

demand to obtain an estimate of monthly peak demands. The annual peak (for residential demand) is the maximum of the monthly peak demand estimates.

4.2.3 Methodology for commercial energy and peak demand forecasts

We forecasted annual commercial demand by regional grouping. The explanatory variables in our commercial analysis are summarized in Table 2-4.

Explanatory variables	Note
Commercial electricity sales price (com_price)	We use the IHS Markit November 2019 ERCOT wholesale power price forecast, with estimated conversion to a commercial retail price. The growth rate (estimated at 1.4 percent) from 2019 to 2030 is then used to create a smooth trajectory of retail prices so that the longer-term retail price trend is captured in the econometric equations without distorting month-to-month patterns in power consumption in our forecast. Historical retail prices are taken from the US Energy Information Administration (EIA).
Gross county product (GCP)	IHS Markit macroeconomics outlook for West Texas. Historical data taken from Bureau of Economic Analysis (BEA).
Cooling degree days (CDD)/Heating degree days (HDD)	We use Midland metropolitan numbers from NOAA as history and 10-year average for the forecast. Our forecast assumes that the most recent 10-years of weather data are "weather normal."

Table 2-4. Explanatory variables in the commercial electricity demand forecast

We have grouped the counties as shown in Table 2-5 These groupings are largely consistent with the groupings used for the industrial electricity demand forecasts.

Grouping Name	Counties included
Central Basin	Andrews, Crane, Ector, Gaines
Delaware Basin	Culberson, Loving, Pecos, Reeves, Ward, Winkler
Midland Basin and Fringe	Glasscock, Howard, Martin, Midland, Reagan, Upton, Borden, Dawson, Mitchell, Scurry, Sterling, Irion

Table 2-5 County groupings for commercial electricity demand forecast

The following is the general econometric equation that we used in the commercial sector:

$$\log(\text{com\_demand\_grouping}) = \beta_1 \log(\text{com\_price}) + \beta_2 \log(\text{GCP\_grouping}) + \beta_3 \log(\text{CDD}) + \beta_4 \log(\text{HDD}) + \text{Constant}$$

After forecasting commercial demand for each county using forecasts of the explanatory variables, we take the following additional steps:

- Apportioning the groupings' annual demand to county-level demand: The demand growth in a regional grouping is apportioned to each county based on the county's share of GCP growth. The only exception is in 2020, when the GCP growth is negative, regionally, and overall demand growth is also projected to be negative – in this case, the (small) demand growth rate for 2020 in the regional grouping is applied uniformly to all counties in the group. In the small load counties (Sterling, Gaines, and Irion), we use the adjacent counties' demand growth rate to approximate their demand growth.

- Disaggregating annual energy demand to monthly energy demand using the average monthly fraction inferred from the electricity billing data.
- Adjusting the results for a 4% distribution loss factor for residential / commercial demand. This "grosses up" the sales-level data to the distribution substation level. Accordingly, we divide the monthly energy forecasts by 0.96.

- Converting monthly energy demand to annual peak demand by county: We use the 15-minute interval data to calculate commercial load factors for each county in each month. The load factor is applied to the monthly energy demand to obtain an estimate of monthly peak demands. The annual peak (for commercial demand) is the maximum of the monthly peak demand estimates.

4.2.4 Econometrics Modeling

The IHS Markit Economics approach to state models represents a significant departure from most previous multi-regional modeling and forecasting efforts. Most other regional models are constructed as proportions of the United States. In the IHS Markit system, however, each area is modeled individually and then linked into a national system. Thus, our models do not forecast regional growth as simple proportions of U.S. totals, but focus on internal growth dynamics and state specific business cycle response. This approach is referred to as "top-down bottom-up." It contrasts sharply with pure share (top-down) models, and models that are not linked to a national macroeconomic model (bottom-up) and contains the best of both approaches.

Our basic objective is to project how regional activity varies, given an economic environment as laid out by IHS Markit Macroeconomic and Industry forecasts. Important regional issues are addressed using information about detailed industrial mix, inter-industry and interregional relationships, productivity and relative costs, and migration trends.

IHS Markit maintains separate models for 50 states and the District of Columbia. The state models have the following basic characteristics:

- Each state is modeled individually, with different model structures and concept coverage specified according to the characteristics of the state
- National policy is explicitly captured,

These models are econometrically estimated and contain about 250 or more equations each. Employment, wage rates, and GSP by NAICS sector, along with income by type of activity, are modeled in detail. Other concept coverage includes population and its components of change, housing starts, retail sales, and the consumer price index. The models have the ability to forecast income, wages, and GSP in nominal as well as real dollars. Because the models are econometric with a quarterly periodicity, they are able to capture the full business cycle behavior of the economy, including the timing and amplitude of the turning points.

Another general characteristic of the models is that they are policy sensitive — they respond to changes in tax rates, military spending, utility costs, etc. The policy simulation capability can be broadly classified into two types. First, the models can capture how a state economy responds to changes in the national economy resulting from national or international events or a policy change. The second type of simulation these models can perform efficiently is an analysis of state government policies.

These models are re-specified and re-estimated periodically to account for new/updated historical information.

4.2.4.1 Example of residential energy and peak demand forecasts – Ward County

We forecasted the residential electricity energy demand for Ward County at the annual level. The resulting annual energy usage forecast is shown in Figure 2-3, along with the relevant historical data.

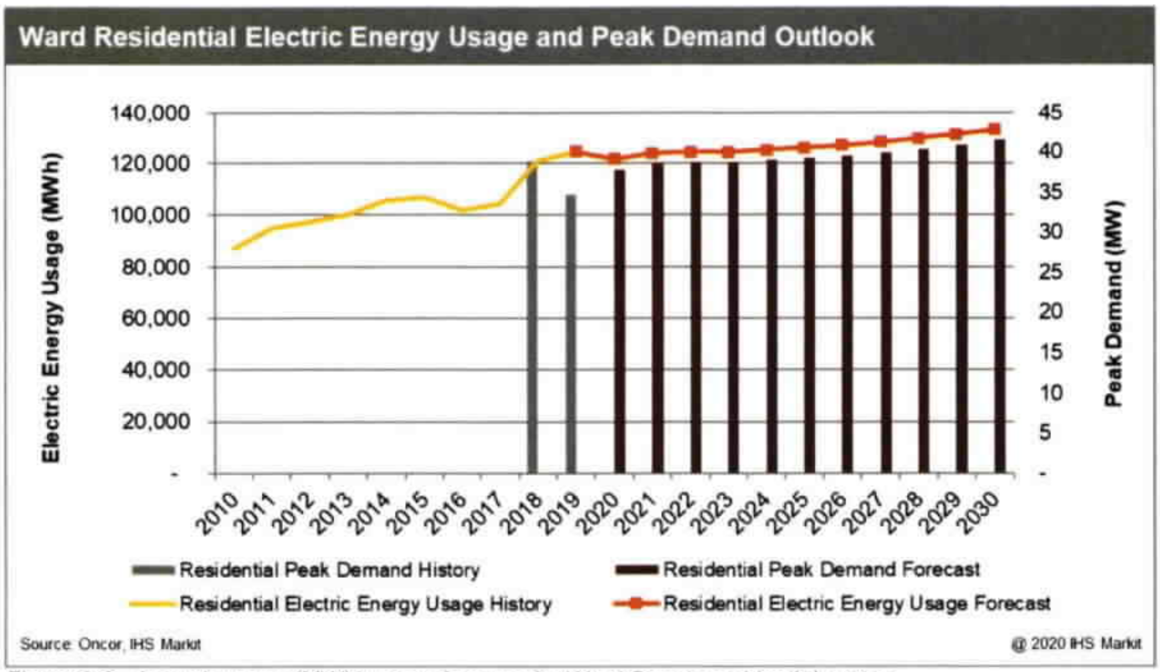


Figure 2-3: Annual energy (MWh) usage forecast for Ward County residential sector

We then adjusted the annual energy forecast for distribution losses to scale up to the distribution substation level (1/0.96).

Then, we apportioned the annual energy demand into the months based on the historical monthly shares of residential energy demand.

Month	Ward County, monthly apportionment of annual residential energy demand
Jan	9%
Feb	7%
Mar	6%
Apr	6%
May	8%
Jun	10%

Jul	12%
Aug	11%
Sep	9%
Oct	7%
Nov	7%
Dec	9%

Table 2-6. Ward County monthly apportionment of residential energy demand
Note: Numbers may not sum to 100% due to rounding.

We then converted the monthly energy to a monthly peak demand based on our calculated residential load factors.

Month	Ward county residential load factor
Jan	0.55
Feb	0.52
Mar	0.45
Apr	0.42
May	0.47
Jun	0.55
Jul	0.52
Aug	0.54
Sep	0.51
Oct	0.44
Nov	0.47
Dec	0.61

Table 2-7 Ward County residential load factors

Residential energy demand in Ward County is projected to grow 0.6% annually from 2019 to 2030. The peak demand is projected to grow 1.6% (annually) from 2019 to 2030. The peak demand growth rate is higher than the energy demand growth rate (over this period) because the 2019 peak demand was unusually low.

4.2.4.2 Example of commercial energy and peak demand forecast – Ector County

This commercial example is for Ector County, which is in our Central Basin Platform grouping. We forecasted the commercial electricity energy demand for the Central Basin Platform at the annual level. The resulting annual energy usage forecast is shown in Figure 2-4, along with the relevant historical data.

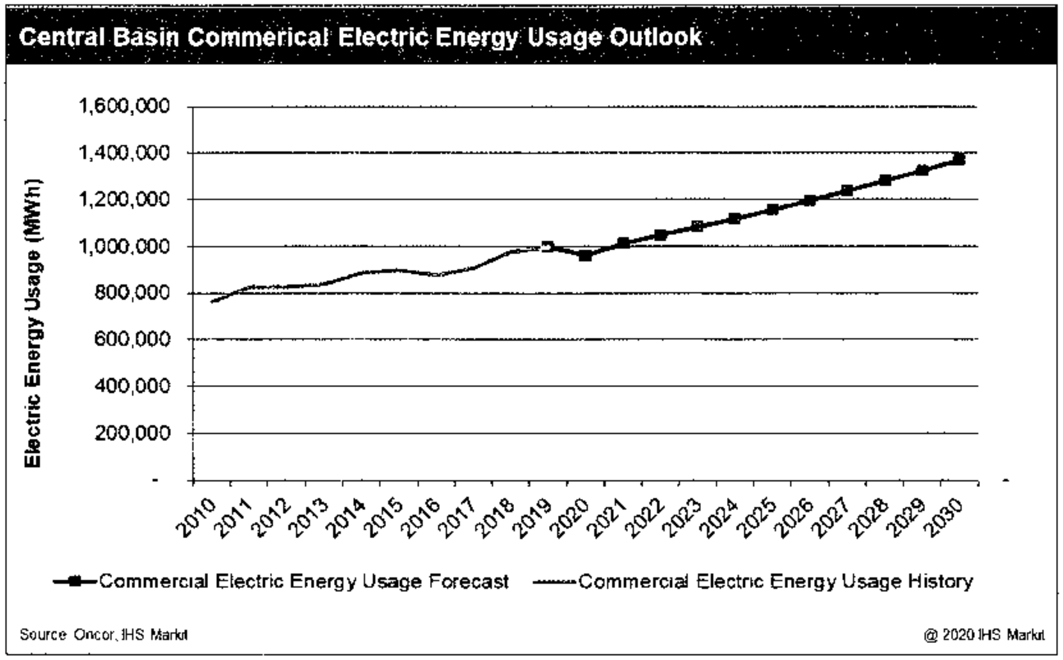


Figure 2-4 Annual energy (MWh) usage forecast for Central Basin Platform commercial sector

We then apportioned the regional grouping's demand growth to Ector County based on Ector's GCP growth relative to the GCP growth for the same grouping. We are sharing out the grouping's projected commercial electricity demand growth based on the GCP shares of growth for the grouping.

We then adjusted the annual energy forecast for distribution losses to scale up to the distribution substation level (1/0.96).

Then, we apportioned the annual energy demand into the months based on the historical monthly shares of commercial energy demand.

Month	Ector County, monthly apportionment of annual commercial energy demand
Jan	8%
Feb	7%
Mar	7%
Apr	8%
May	9%
Jun	10%
Jul	10%
Aug	10%
Sep	9%
Oct	8%
Nov	7%
Dec	8%

Table 2-8: Ector County monthly apportionment of commercial energy demand

Note: Numbers may not sum to 100% due to rounding.

We then converted monthly energy usage to monthly peak demand based on our calculated commercial sector load factors.

Month	Ector county commercial load factor
Jan	0.69
Feb	0.67
Mar	0.62
Apr	0.58
May	0.60
Jun	0.65
Jul	0.65
Aug	0.64
Sep	0.63
Oct	0.57
Nov	0.66
Dec	0.69

Table 2-8: Ector County commercial load factors

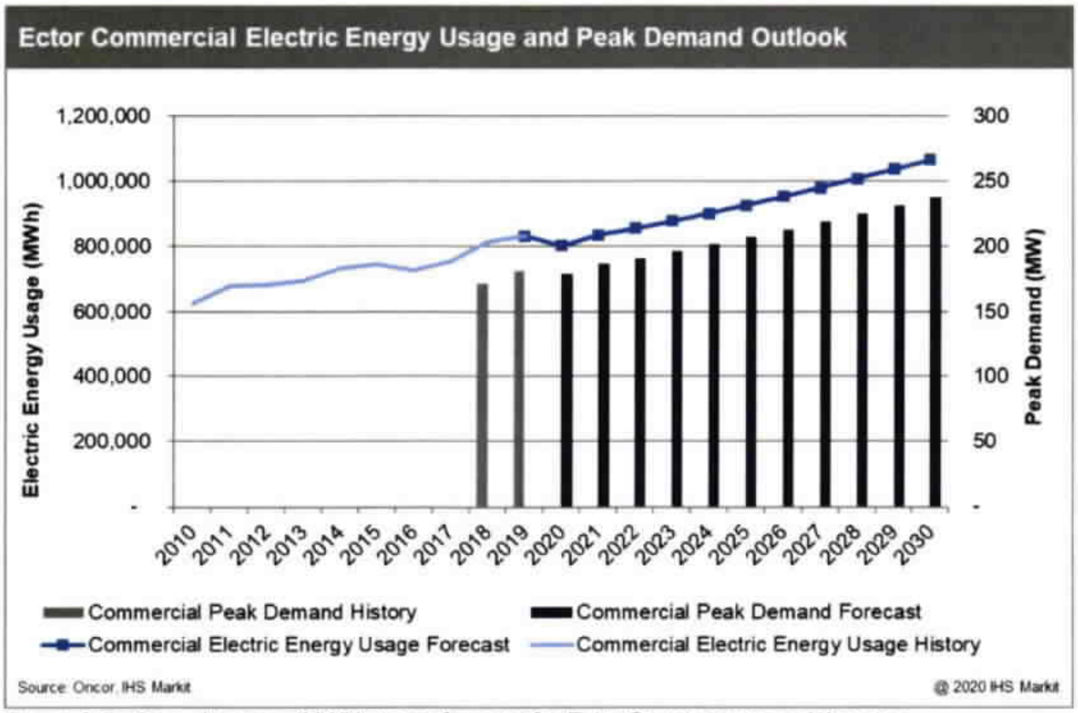


Figure 2-5: Annual energy (MWh) usage forecast for Ector County commercial sector

Commercial energy usage in Ector County is projected to grow 2.3% annually from 2019 to 2030. The peak demand is projected to grow 2.1% (annually) from 2019 to 2030.

4.2.5 Residential and Commercial Peak Demand Results

Applying the same methodology discussed above for Ward (residential) and Ector (commercial) counties, we forecasted the residential and commercial annual peak demands for all of the counties in this study. These are shown below.

Residential annual peak (MW)					
County	**2019**	**2020**	**2025**	**2030**	**CAGR 2019-2030**
ANDREWS	33	32	36	40	2.0%
CRANE	14	13	15	16	1.3%
ECTOR	278	263	299	335	1.7%
GAINES	<1	<1	<1	<1	5.5%
CULBERSON	<1	<1	<1	<1	-1.5%
LOVING	<1	<1	<1	1	8.1%
PECOS	14	15	14	15	1.0%
REEVES	1	1	1	1	4.4%
WARD	35	38	39	41	1.6%
WINKLER	4	4	5	5	2.2%
BORDEN	1	1	1	1	1.1%
DAWSON	25	25	26	27	0.7%
GLASSCOCK	7	7	7	8	1.5%
HOWARD	53	69	71	75	3.2%
MARTIN	11	11	11	9	-1.8%
MIDLAND	326	349	377	365	1.0%
MITCHELL	N/A	15	16	17	N/A
REAGAN	1	1	1	1	1.3%
SCURRY	N/A	25	26	29	N/A
UPTON	1	1	1	1	3.4%
IRION	<1	<1	<1	<1	2.0%
STERLING	<1	<1	<1	<1	-0.7%

Table 2-9 Annual residential peak demand by county

Commercial annual peak (MW)					
County	**2019**	**2020**	**2025**	**2030**	**CAGR 2019-2030**
Central Basin Group					
ANDREWS	28	27	42	56	6.5%
CRANE	15	14	17	21	3.3%
ECTOR	186	179	207	238	2.3%
GAINES	4	4	6	8	6.5%
Delaware Basin Group					
CULBERSON	6	6	6	6	0.0%
LOVING	9	9	17	27	9.9%
PECOS	46	44	45	46	-0.1%
REEVES	59	57	64	73	2.0%
WARD	49	47	48	51	0.5%
WINKLER	12	12	12	13	0.4%
Midland Basin + Fringe Group					
BORDEN	10	10	10	10	0.0%
DAWSON	20	19	19	19	-0.2%

GLASSCOCK	45	44	44	44	-0.1%
HOWARD	56	55	56	57	0.1%
MARTIN	64	62	68	71	1.0%
MIDLAND	265	259	267	268	0.1%
MITCHELL	9	9	9	9	-0.2%
REAGAN	17	17	18	19	1.1%
SCURRY	N/A	19	19	20	N/A
UPTON	13	13	15	16	1.7%
IRION	<1	<1	<1	<1	0.1%
STERLING	<1	<1	<1	<1	0.1%

Table 2-10: Annual commercial peak demand by county

Note: 2019 commercial annual peaks are from model results

4.3 Total Forecasted Peak Load

4.3.1 Combining the Residential-Commercial with the Industrial Forecast

In order to provide the full picture of peak power in the Permian counties, the monthly peak forecasts of the residential, commercial, and industrial peaks must be combined. However, these cannot be accurately added together without consideration of their coincidence factors.

Annually, each sector has its own power peak, which may occur in a summer month for residential and commercial or later in the year for industrial under high growth conditions. Monthly coincidence factors were calculated from the 15-minute interval data to describe the ratio between the overall coincident peak and the sum of the non-coincident peaks of the individual sectors. The 15-minute data used to develop the coincidence factors only considers loads supplied by Oncor.

4.3.2 Calculating the Inter-sector Coincidence Factor

The calculation of the coincidence factors includes:

- Examination of the county-level 15-minute data for the residential, commercial, and industrial sectors, individually and summed together
- For each month, finding the total (coincident) peak for all sectors in combination
- For each month, finding the peak for each sector (which can occur at different times) and sum these non-coincident peaks together
- Dividing the coincident peak by the sum of the non-coincident peaks
- For each month, taking the average of coincidence factors calculated from 2018 and 2019 15-minute data. The only exception is December, where only 2018 data is available.

Example: Calculation of Midland March coincidence factor

$$Peak_{total\_2018\_Mar} = Peak_{res\_2018\_Mar} + Peak_{com\_2018\_Mar} + Peak_{ind\_2018\_Mar}$$

$$= 124{,}043\ KW + 166{,}100\ KW + 202{,}922\ KW$$

$$= 493{,}065\ KW$$

$$Coincident\ Peak_{total\_2018\_Mar} = 450{,}131\ KW$$

$$Coincident\ Factor_{total\_2018\_Mar} = \frac{Coincident\ Peak_{total\_2018\_Mar}}{Peak_{total\_2018\_Mar}} = 0.91$$

Monthly coincidence factors ranged from 0.75 to 0.99. Overall, Reeves has the largest average coincidence factor (0.98) and Ector has the smallest (0.92).

4.3.3 Forecasting All Power

Despite not having data from all energy providers in all counties, the power forecasted by IHS in each sector considers the power supplied from all TDSPs (Transmission and Distribution Service Provider). Oncor power data for the residential and commercial peak demands had to be adjusted in the same way the industrial average load data was adjusted to account for all power. The total power for all sectors calculated from the Oncor data was divided by the estimated portion of coverage Oncor supplied in a county. The scaling up to consider all TDSPs was applied throughout the forecast.

The resulting sequence of 12 monthly coincidence factors describing January to December were multiplied with the sum of the peaks from each sector resulting in a total peak forecast by county. In order to roll up the counties into a single lump for the entire Permian or for areas of the Permian, the arithmetic average of the monthly coincidence factors of each component county was applied. This does imply perfect coincidence between counties, which is unlikely, but zero diversity has been assumed for the sake of the study. Inter-county coincidence factors have not been calculated.

For the following counties, no residential or commercial data was available: Crockett and Schleicher. Their residential and commercial contribution to the total peak was excluded, and their inter-sector coincidence factor was not calculated. In summary charts with more than one county, the average coincidence factor is the arithmetic average of the counties that did have coincidence factors calculated. This means the forecast summaries for the Midland Basin and Fringe areas will be under the actual power demand.

The graph below has four elements which account for the sector peaks, their coincidence factor and the resulting coincidence peak.

The four elements on the graph are as follows:

- **Commercial+Residential Peak Monthly (MW):** In green, this shows the peak power usage (non-coincident) from the commercial and residential sectors when analyzing them separate from the industrial. There is a high degree of seasonality, with much higher loads in the summer, especially due to demand from air conditioning. The green depicts the non-coincident sum of commercial and residential peak demand, although it must be noted these sectors in fact tend to be highly coincident.

- **Industrial Peak Monthly (MW):** In red, this shows the peak power usage, in isolation, from the industrial sector

- **Coincidence Factor of Residential, Commercial, and Industrial Peak:** A yellow line, a value less than 1.0 that shows the relationship between commercial+residential+industrial peak demand additivity. Historical relationships are assumed to continue in the future, so this line shows a regular pattern through 2030 for each county. The determined annual pattern is repeated through 2030.

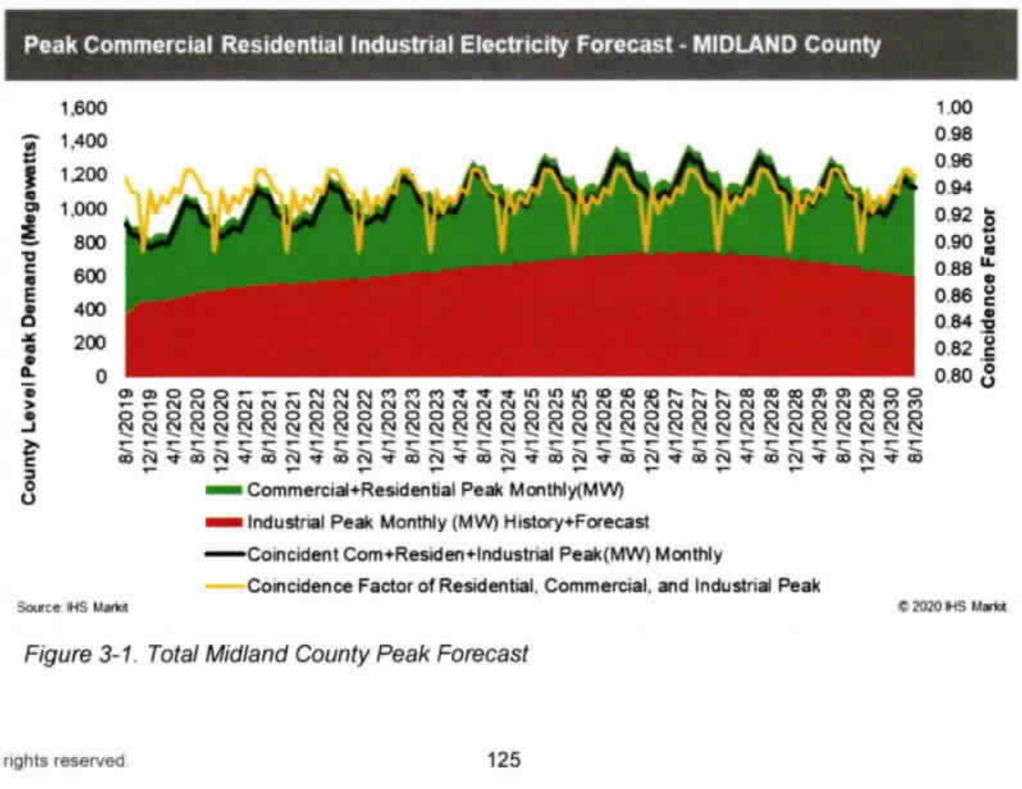
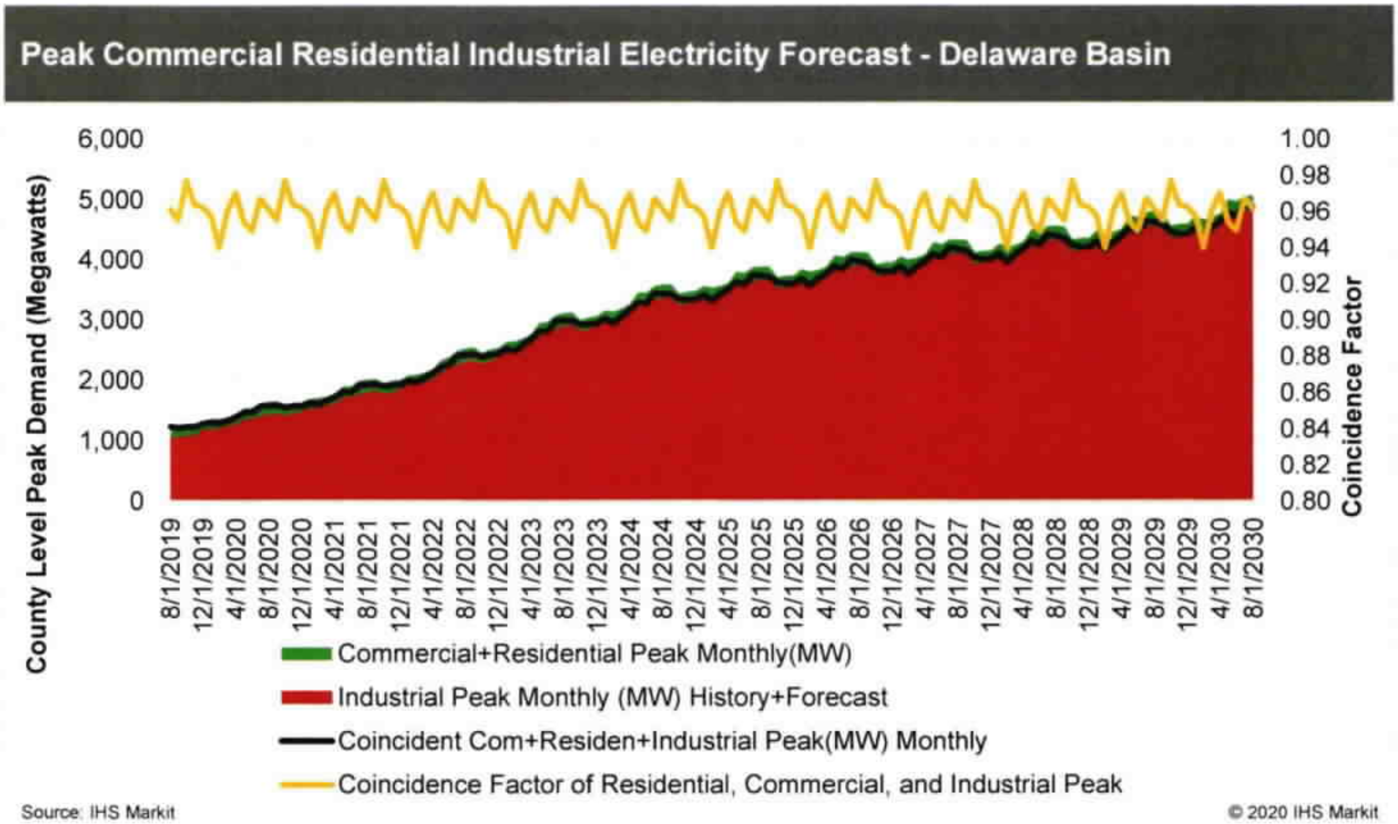


Figure 3-1. Total Midland County Peak Forecast

- **Coincident Commercial+Residential+Industrial Peak (MW) Monthly:** This is the black line. It is always less than the top of the green graph. Visually, it is calculated as the (green + red) *yellow line. If, for example, there is 500 MW of industrial peak demand and 250 MW of commercial peak demand and 250 MW of residential peak the actual total shown in the black line it would not be 1,000 MW, but instead 1,000 MW * the coincidence factors. The average monthly coincidence factors applied to the entire Permian region range from 92% to 94%. The total peak would be the total 1,000 MW multiplied by 0.92 to 0.94 for most of the year. This gives 920 MW to 940 MW as a coincident peak.

4.3.4 Peak Load Forecast by Region

The Delaware Basin's power demand is completely dominated by the industrial sector where oil and gas activity is expected to grow. Growth is expected within the residential and commercial sectors, but it will constitute a small fraction of the power forecast in the Delaware Basin. The average monthly coincidence factors for this region range from 0.94 to 0.98. Peak power for all sectors is expected to increase by 294% from 1,300 MW at the 2019 peak to 4,900 MW at the 2030 peak.



Source: IHS Markit

Figure 3-2. Total Delaware Basin Peak Forecast

The Midland Basin's power demand has a large contribution from residential and commercial activity, but the industrial sector accounts for the majority of the existing load. Since the growth rate in the industrial sector will be higher, the residential and commercial power will become a smaller percentage of the load served over the next decade. The average monthly coincidence factors for this region range from 0.94 to 0.97. Peak power for all sectors is expected to increase by over 56% from just over 2,040 MW at the 2019 peak to nearly 3,200 MW at the 2030 peak.

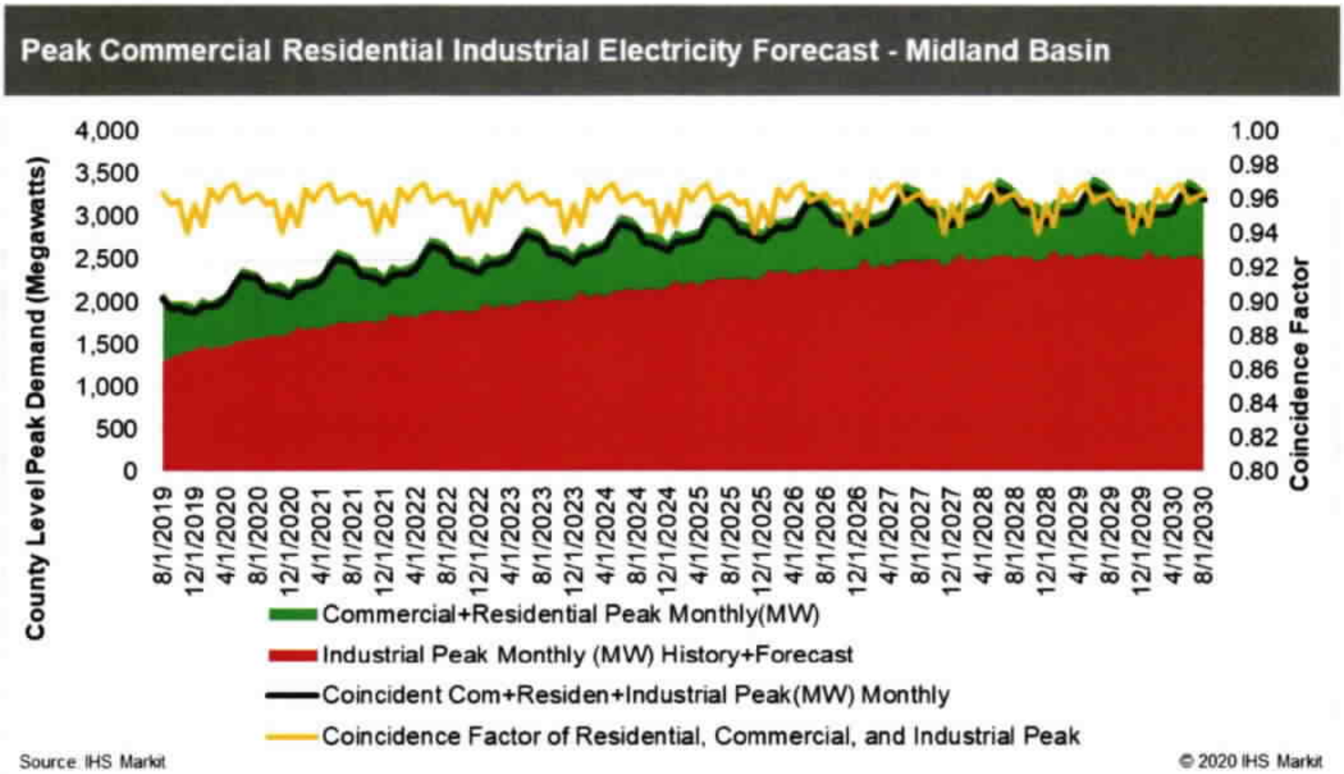


Figure 3-3. Total Midland Basin Peak Forecast

The Central Basin Platform's power demand has a substantial contribution from residential and commercial activity much like the Midland Basin. However, residential and commercial power will become even more important over the next decade as the oil and gas activity stagnates in this region. The average monthly coincidence factors for this region range from 0.93 to 0.96. Peak power for all sectors is expected to increase by 10% from 1,250 MW at the 2019 peak to just 1,370 MW by the 2030 peak.

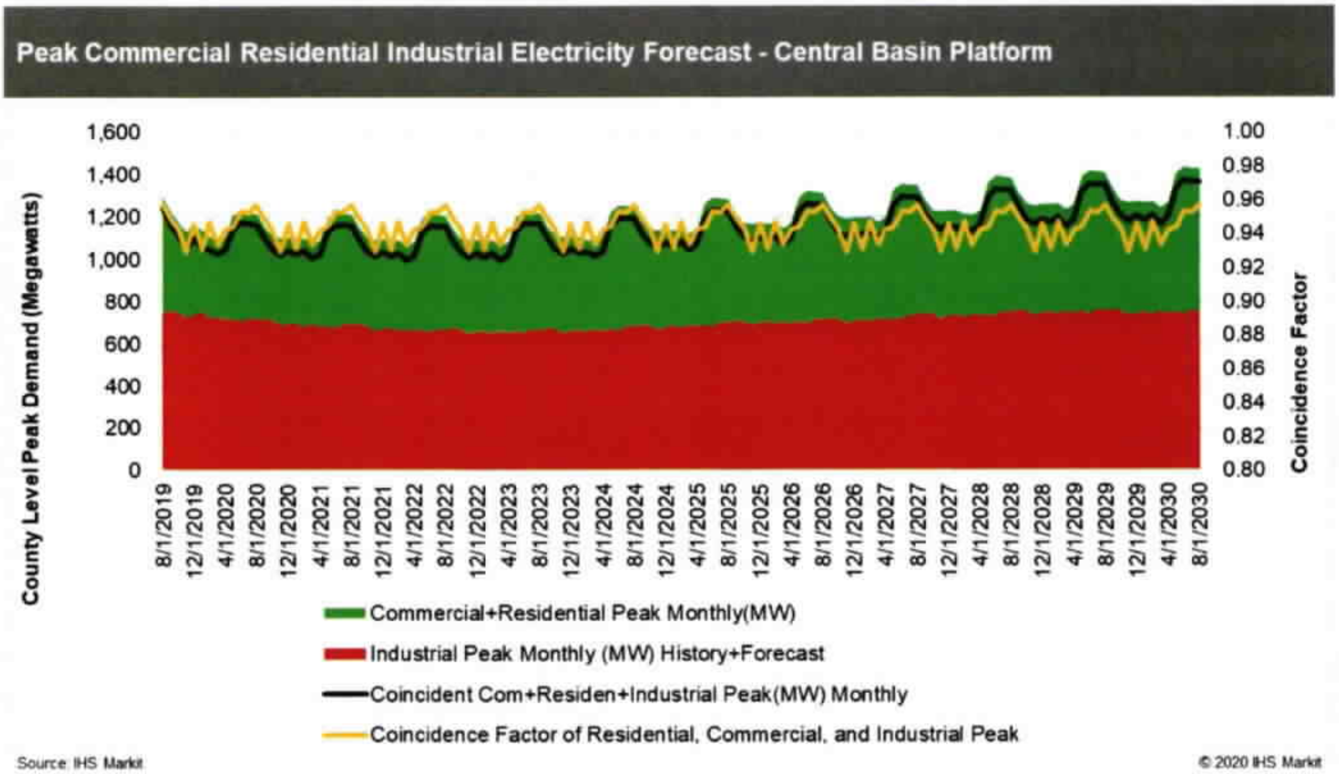


Figure 3-4. Total Central Basin Platform Peak Forecast

Power demand in the Fringe area of the Permian Basin currently has only a minor contribution from residential and commercial activity which is expected to remain relatively constant throughout the study. Most of the Fringe area's growth will come from the industrial sector, but growth will be limited since oil and gas activity is not expected to ramp up much over the next decade. The average monthly coincidence factors for this region range from 0.93 to 0.96. Peak power for all sectors is expected to increase by only 24% from 570 MW at the 2019 peak to 710 MW at the 2030 peak.

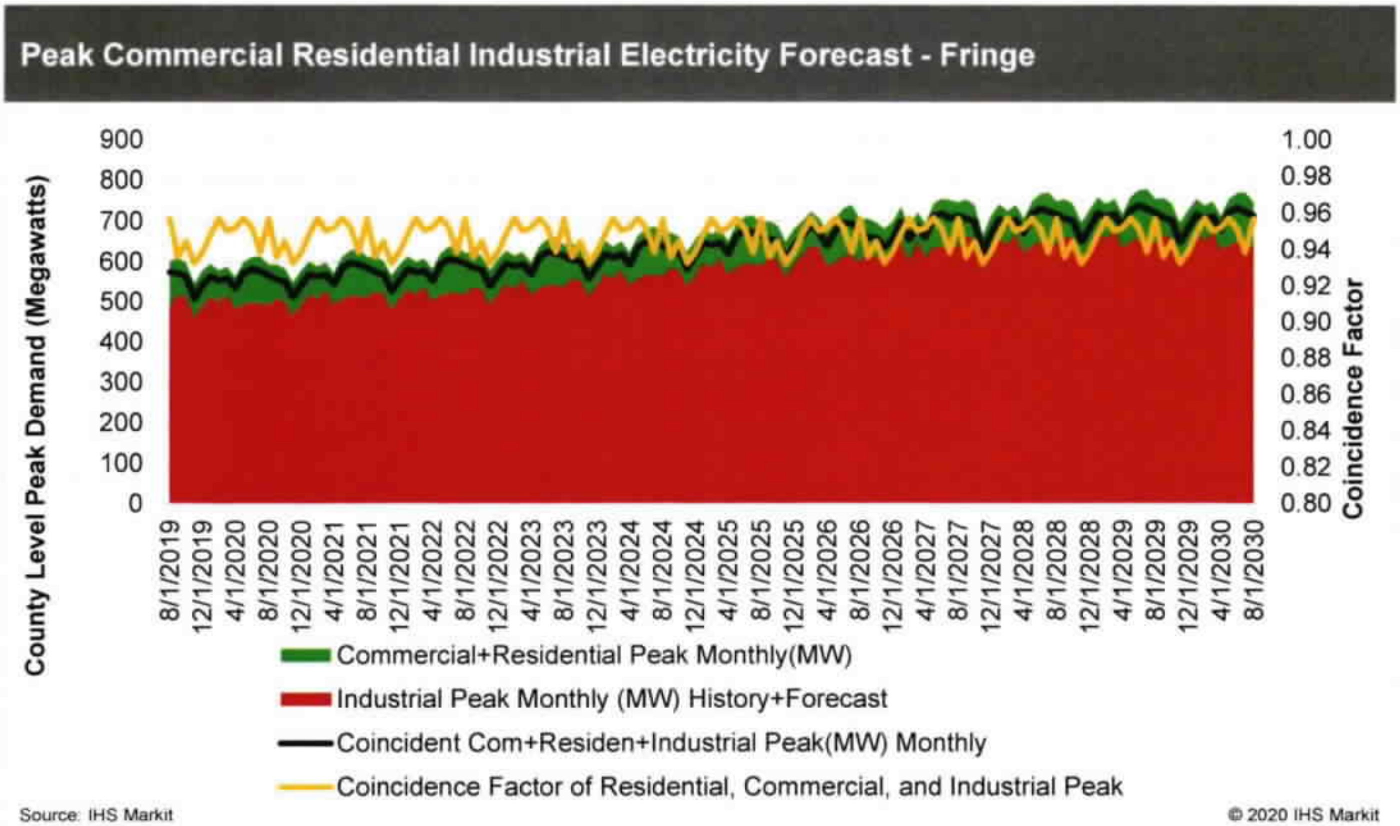


Figure 3-5. Total Fringe Area Peak Forecast

4.4 Total Permian Peak Load Forecast

Overall, the Permian region's power demand is dominated by the industrial sector where most of the growth is expected. Still, power demand is expected to grow in all sectors. The average monthly coincidence factors applied to the entire Permian region range from 94% to 98%. Peak power for all sectors is expected to almost double from just under 5,200 MW at the 2019 peak to nearly 10,200 MW at the 2030 peak.

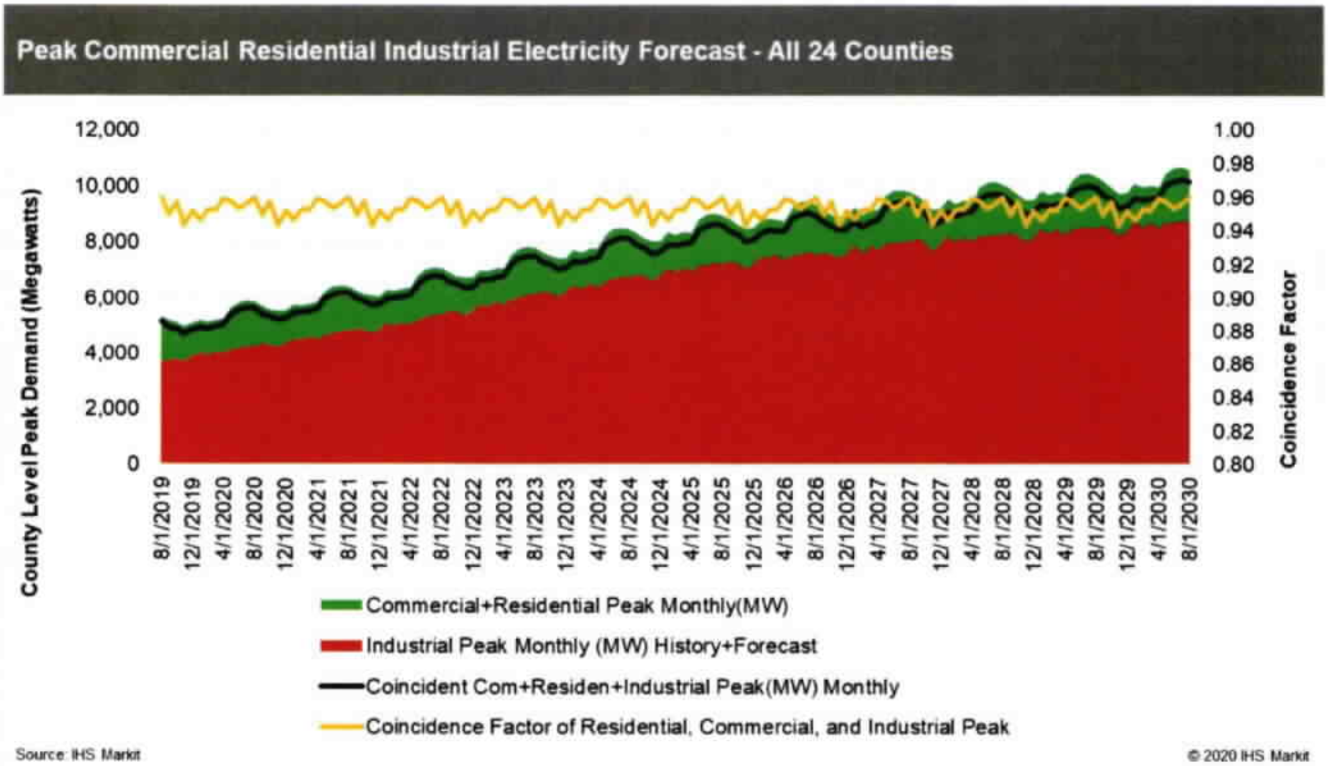


Figure 3-6. Total Permian Far West Texas Weather Zone Peak Forecast by

In the chart below (figure 3-7) it can be seen that the Delaware Basin load is expected to have the highest growth rate in the Permian through 2030. From 2019 to 2030 the Delaware Basin is expected to move from being a moderate component of the Permian power used to comprising over half of the total load as its growth rate is expected to be very high. The other areas of the Permian are also expected to grow, but their industrial sectors are limited by weaker geological potential. Current and projected growth for all regions is also summarized in table 3-1 below.

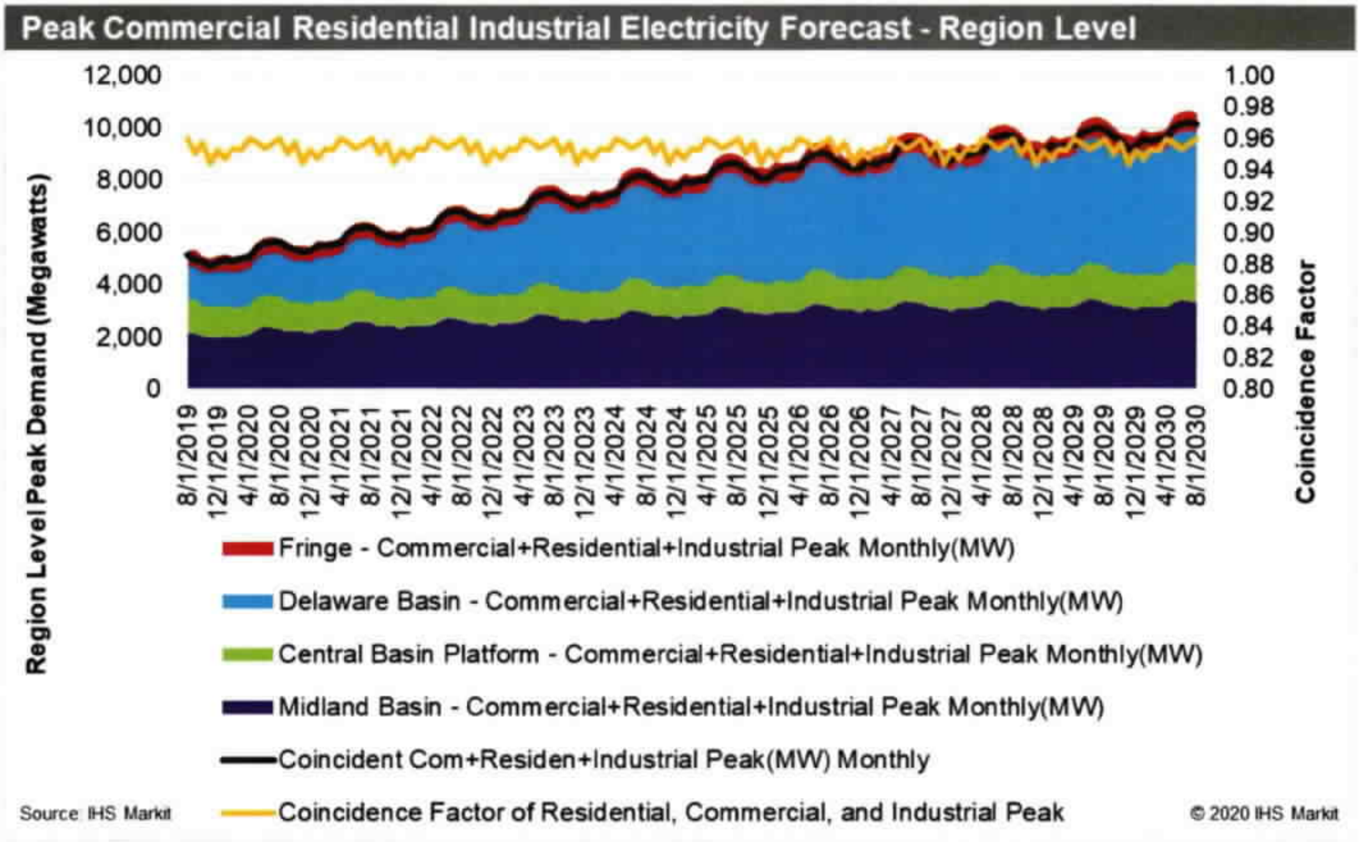


Figure 3-7. Total Permian Far West Texas Weather Zone Peak Forecast by Region

Region	Current	2030 Forecast	Increase
Delaware Basin	1,300 MW	4,900 MW	294%
Midland Basin	2,040 MW	3,200 MW	56%
Central Basin	1,250 MW	1,370 MW	10%
Fringe	570 MW	710 MW	24%
Total	5,160 MW	10,200 MW	97%

Table 3-1. Summary of total load increases by region for the Permian Basin.

Thomas Yamin, P.E.
Director
Regulatory – Transmission and Planning

July 25, 2023

David Smeltzer
Division Director
Rules and Projects
Public Utility Commission of Texas
1701 N. Congress Ave
Austin, TX 78711-3326

Dear Mr. Smeltzer:

RE: Project No. 55249, REGIONAL TRANSMISSION RELIABILITY PLANS

In response to your July 17, 2023 request in the abovementioned proceeding, Oncor Electric Delivery Company LLC ("Oncor") is providing the Public Utility Commission of Texas ("Commission") with the Oncor-Commissioned IHS Markit study, *West Texas Forecasted Load Additions: Permian Basin*, dated April 6, 2020. This study was originally filed in Docket No. 27706 on April 27, 2020 (Item No. 439).

If you have questions about the enclosed information, please contact me at (214) 486-3512.

Respectfully submitted,

Thomas J Yamin

Thomas Yamin, P.E.

Enclosure

1616 Woodall Rodgers Freeway, Dallas, Texas 75202
214.486.3512. | Oncor.com