Public

Integrated Resource Plan

4 CSR 240-22.030

Load Analysis and Forecasting

Volume 3

February 2008

4 CSR 240-22.030 (6)

(6)

AmerenUE did seek and receive a waiver from this requirement because the rule's purpose is to provide a basis for the high and low load forecasts under 4 CSR 240-22.030 (7), but this use would be made unnecessary under waiver request received for 4 CSR 240-22.030 (7). The sensitivity analysis described in section 4 CSR 240-22.030 (6) would be replaced by the development of a subjective probability distribution over load forecasts in the development of the probability tree of scenarios.

4 CSR 240-22.030 (7)

(7) Based on the range of load forecasts that are reflected in the probability tree of scenarios, AmerenUE will select at least two (2) additional load forecasts (a high-growth case and a low-growth case) that bracket the base-case load forecast. Subjective probabilities shall be assigned to each of the load forecast cases in a manner that is consistent with their subjective probabilities as part of the probability tree. These forecasts and associated subjective probabilities shall be consistent with inputs to the strategic risk analysis required by 4 CSR 240-22.070.

Preliminary sensitivity analysis winnowed out three uncertain factors critical to the performance of AmerenUE's candidate resource plans: (1) greenhouse gas policy outcomes, (2) natural gas prices, and (3) load growth paths. The various combinations of these three key uncertain variables, and their associated likelihoods, formed the scenarios represented in the final probability tree. As described in the waiver request related to 4 CSR 240-22.070, these scenarios are analyzed as a set of model runs, whose outputs then constitute the key inputs to the standard risk analysis and strategy selection phases of the IRP process. One of the essential model outputs is the projection of future loads in AmerenUE's service territory. Accordingly, a distinction needs to be made between these demand outputs and the load growth forecasts that are exogenous inputs into the model of the national energy and environment system.

The final probability tree appearing in Step 1 of Figure 1 below represents the set of scenarios that the AmerenUE IRP process explicitly considers. AmerenUE developed mutually consistent sets of input assumptions for each scenario through the application of CRA International's (CRA) MRN-NEEM[1] model of the energy and environmental system. This integrated model is able to simultaneously simulate interactions in fuel markets, energy demands, electricity generation system operation, non-electricity sector outcomes, macroeconomic activity levels, and responses to emissions limits that may be applied to sources throughout the economy, and not just to electricity generators. Thus, the scenarios in the probability tree in Step 1 were in fact analyzed as a set of model runs using the MRN-NEEM model with the above capabilities.

[1] See 4 CSR 240-22.030 Appendix B for an exposition of the MRN-NEEM model.

The "Energy Efficiency" decision nodes represent the set of exogenous load forecasts which are inputs into the model. In contrast, the output of each model run (*i.e.*, for each scenario in the tree) is an integrated set of projections of key inputs to a standard analysis to select a resource plan, as in Step 2 of Figure 1. Each integrated set includes projections through the planning horizon of electricity load growth, as well as changes in wholesale electricity prices, emissions allowance prices (for SO_2, NO_X, Hg, and CO_2), natural gas prices, coal prices, and AmerenUE's optimal emissions control retrofits (and their timing). Thus, as mentioned in the waiver request related to 4 CSR 240-22.070, the development of the scenarios and the associated integrated modeling of those scenarios is its own step that precedes the development of candidate resource plans on a deterministic basis in Step 2.

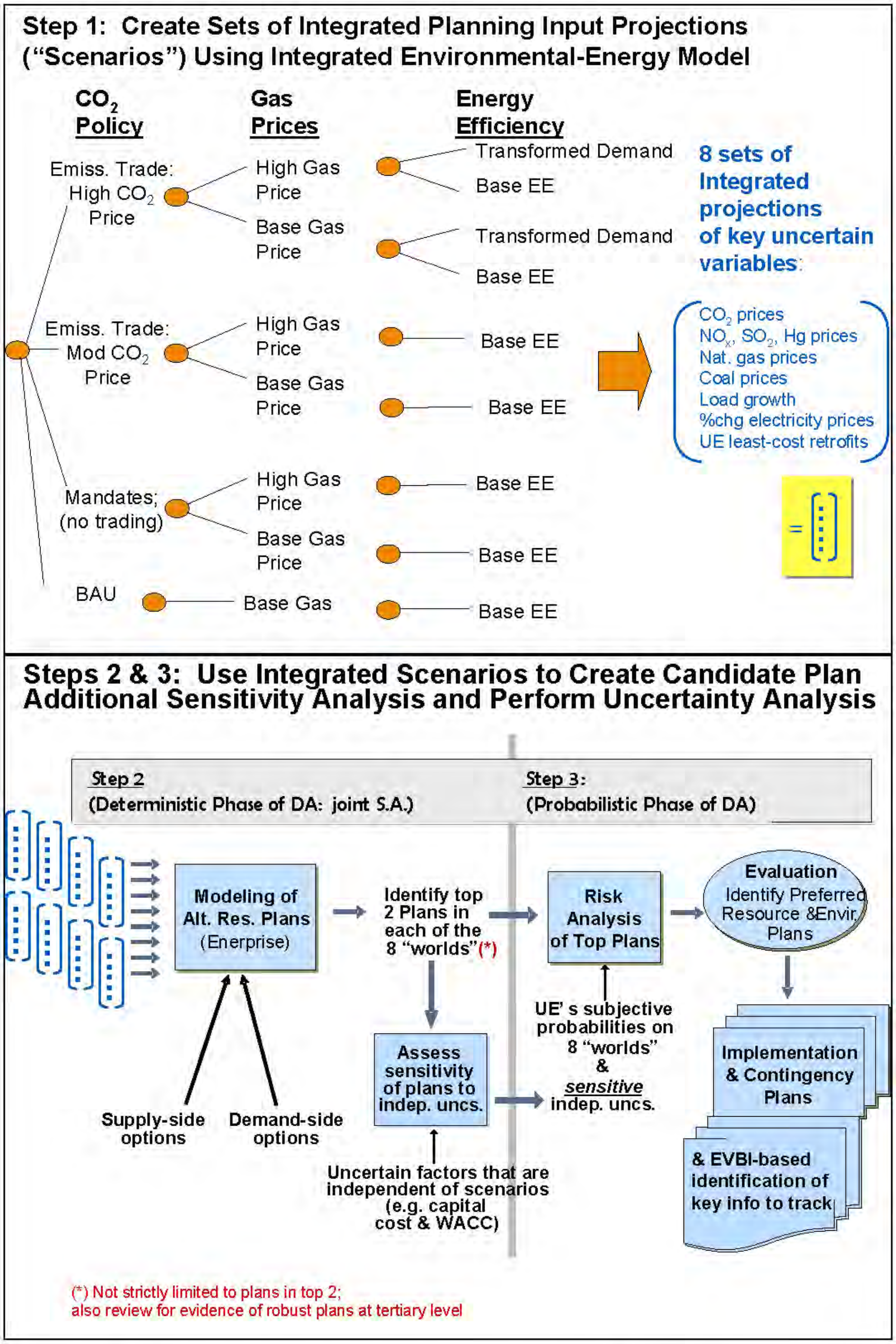

Figure 1: Illustration of Scenario-Based Process for Handling Environmental and Other Risks in IRP.

The two sets of load growth input assumptions that were included in the final probability tree were a "base load" growth case and a "transformed demand" case, as illustrated in Figure 2. The "base load" case represents business-as-usual assumptions in CRA's North American Electricity & Environment Model, or NEEM. From 2007 through 2014, CRA obtains forecasts for both energy, in megawatt-hours (MWh), and peak demand, in megawatts (MW), from the NERC ES&D 10-Year Forecast. These forecasts incorporate historically observed rates of the Autonomous Energy Efficiency Improvement (AEEI) index, which represents general efficiency trends in technology innovation within the entire stock of energy-using goods and services. Thus, the "base load" growth trajectory, in terawatt-hours (TWh), given in Figure 2 below reflects some level of energy efficiency improvement. For each year after 2014, CRA uses the compound average growth rate of annual energy demand from 2009 to 2014.

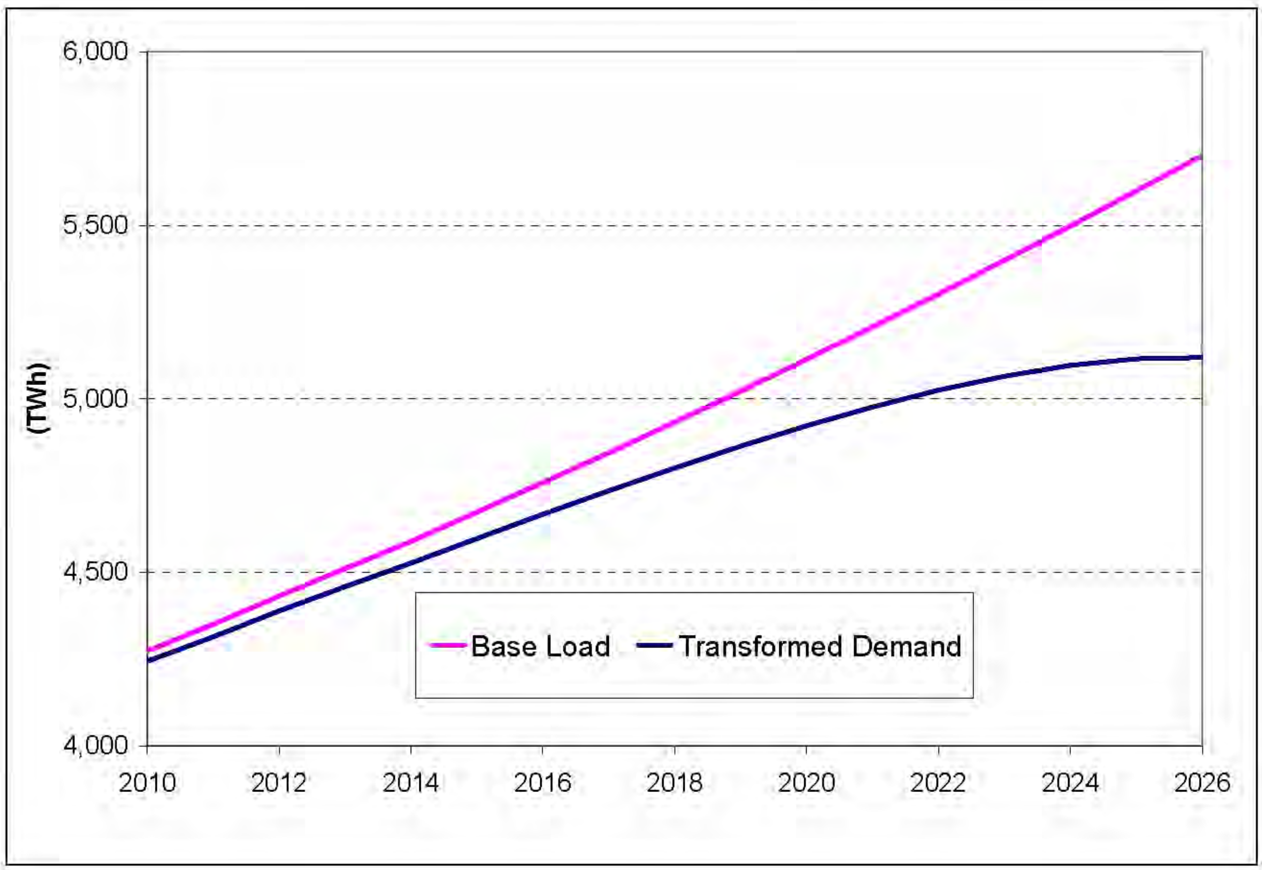

Figure 2: U.S. Electricity Demand (TWh).

As initially structured during the probability elicitation, the "transformed demand" case anticipated both demand-side breakthroughs in the rate of energy efficiency improvement and supply-side advances in distributed generation, which together achieve a 20% reduction in energy demand by 2030. The first component denotes an AEEI rate significantly above the historical levels embodied in the base case load forecast. For the electric sector, CRA calculated an implied base case AEEI by deriving an electricity intensity figure, in kilowatt-hours (kWh) of generation per dollar of GDP. The "transformed demand" case assumes that this measure of the AEEI will increase gradually until it is more than twice the base case rate by 2030, accounting for a 20% decrease in utility demand. The second component is classified as distributed generation, where current utility customers, through federal incentives, cost improvements, or behavioral changes, adopt energy generation technologies that reduce the demand for utility-supplied electricity from the grid. An example of this would be solar applications, particularly photovoltaic module installations on rooftops. This could also include the diffusion of other renewable technologies presently limited in their commercial deployment, such as fuel cells or combined heat and power systems. However, the expert designated by AmerenUE to assign subjective probabilities to each of the above load growth cases assigned very little likelihood to distributed generation accomplishing any meaningful reductions in utility demand. As such, the percentage reductions in load presented in Figure 3 are entirely attributable to demand-side breakthroughs in the rate of energy efficiency improvement, as opposed to any potential supply-side breakthroughs in the distributed generation sphere.

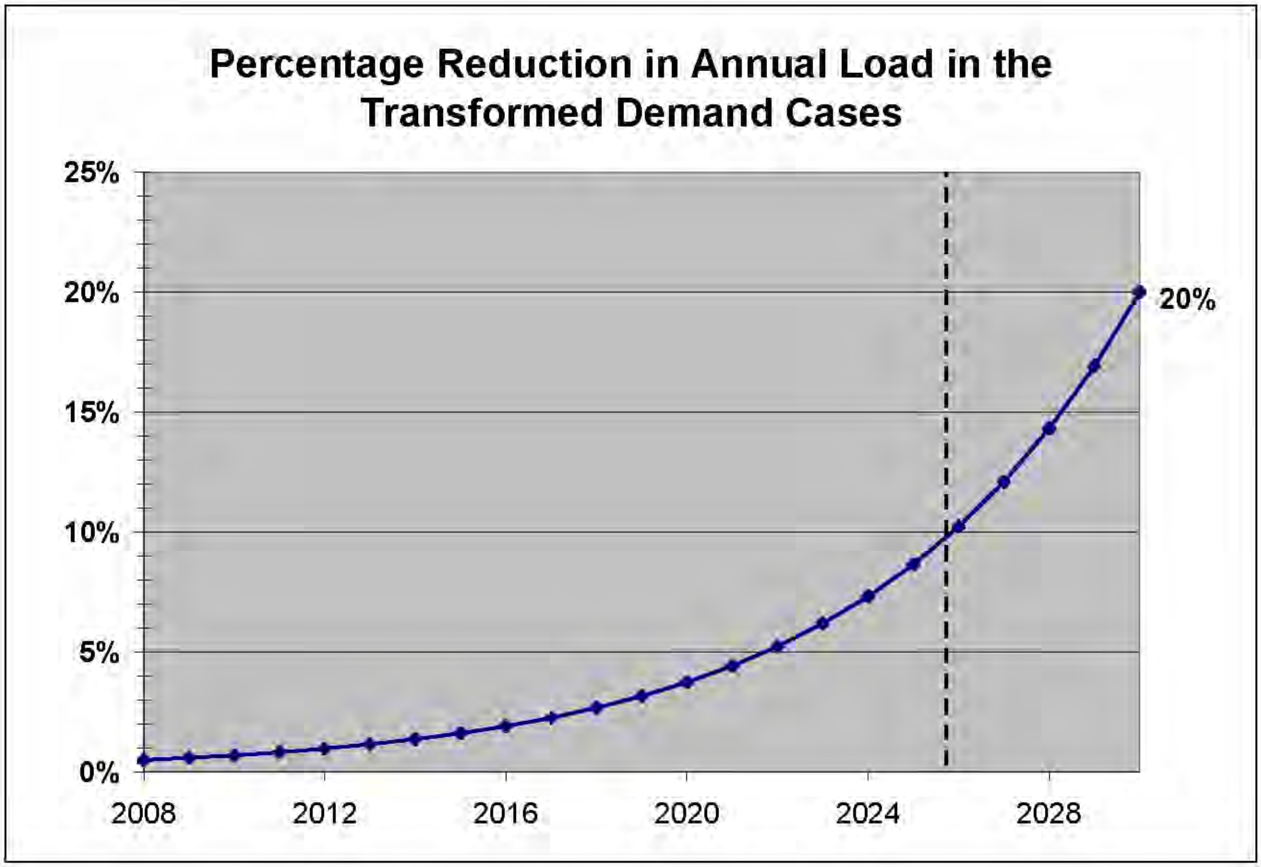

Figure 3: Percentage Reduction in Annual Demand in the Transformed Demand Cases.

An integral component of a risk analysis of an alternative resource plan is the assignment of subjective probabilities to each of the critical uncertainties. That is, the following uncertainties encompassed in the probability tree need to be stated as a probability distribution function (pdf):

1. Greenhouse gas (GHG) policy outcomes, especially in terms of CO_2 price levels;
2. Natural gas prices;
3. **Load growth paths, especially in terms of breakthroughs in energy efficiency and distributed generation.**

Having assigned a probability to each of the three forks in a tree branch, the likelihood of an integrated scenario (*i.e.*, of the endpoint in a tree branch) is simply the product of the probabilities of each fork. As an illustrative example, consider a scenario consisting of the following branches (with subjective probabilities in parentheses): (1) High CO_2 Prices (66%), (2) Base Case Gas Prices (50%), and (3) Base Load (93%). The likelihood of this hypothetical scenario, then, is simply the product of 66%, 50%, and 93%, or roughly 31%.

The elicitation of these subjective probabilities conformed to the formal guidelines of the decision-analytic protocol. One, the appropriate individual to allocate probabilities for a private sector decision is the decision-maker or the person(s) that the decision-maker designates as the best expert(s). If the latter, then the decision-maker still retains the right to accept or modify the conclusions of the designated expert. As such, AmerenUE management identified and directed CRA to work with several specific Ameren in-house experts to obtain probability distributions for each critical uncertain variable. Where multiple experts were interviewed, consensus values were obtained. Senior AmerenUE management (the decision-maker) reviewed the so-determined subjective probabilities and their basis, and approved them for use in the IRP risk analysis. Two, the term "subjective probability" conveys a much more rigid definition in decision analysis than in colloquial conversation. It summarizes the information an individual has of a one-time event or outcome that is not deterministically "known" yet. By definition, then, subjective probabilities of "zero" or "one" are invalid. As mentioned before, these probabilities can naturally vary with the individual, since each expert has different information. Moreover, probabilities can change over time, if and when better information becomes available. Lastly, the term "subjective" does not imply that whatever an expert wants to say is unconditionally relevant. Probability encoding techniques have been designed to elicit an individual's true beliefs about an uncertainty.

CRA structured each probability elicitation session around certain key elements of probability encoding techniques. First, the purpose of the elicitation exercise and process was expressly explained and reinforced interactively throughout the interview. This interactive approach minimizes the potential for "self-encoding" by experts well-versed in probabilistic thinking. Secondly, the variable to be encoded was clearly defined, and if the uncertainty was too complex to analyze as a whole, it was broken down into simpler constituent parts. These more digestible variables were then combined to inform estimates of the more complex outcome. Thirdly, CRA incorporated a "conditioning" phase of the interview to lessen some common sources of cognitive limitations. Visual devices like pie charts and event trees often served as visual and/or mental points of reference on probabilities. Finally, the general philosophy of guiding the thought process, restructuring the investigation, revisiting the thought process, and then verifying results produced probabilities that were robust and truly representative of the experts' beliefs.

To assess AmerenUE's views on the relative likelihood for each of the future load cases, CRA interviewed Rick Voytas, an AmerenUE manager of energy efficiency and demand response. CRA elicited separate probabilities for potential outcomes related to each component of the proposed "transformed demand" case: electricity intensity (kWh use per dollar of GDP) and distributed generation (particularly PV applications), respectively. The diagram in Figure 4 below was instrumental in drawing out Mr. Voytas's expectations for future trends in electricity intensity. The blue line extending through 2006 represents historical data on the net kWh of electricity generated per chained 2003 dollar of gross domestic product (GDP).[2] CRA and Mr. Voytas engaged in a thorough, interactive discussion of the historical and potential impacts appliance standards had and could have on electricity demand by 2026. Special attention was devoted to standards that the Department of Energy (DOE) has mandated will be promulgated between now and 2011, and also to the promise of yet unforeseen additional DOE requirements from 2014 through 2020. In addition, the potential for more energy-efficient building codes and for sweeping behavioral changes in energy consumption over and above DOE directives was also thrashed out.

[2] Historical electrical intensities were based upon Tables 1.5 and 8.2a of the 2006 Energy Information Administration's (EIA) Annual Energy Review (AER).

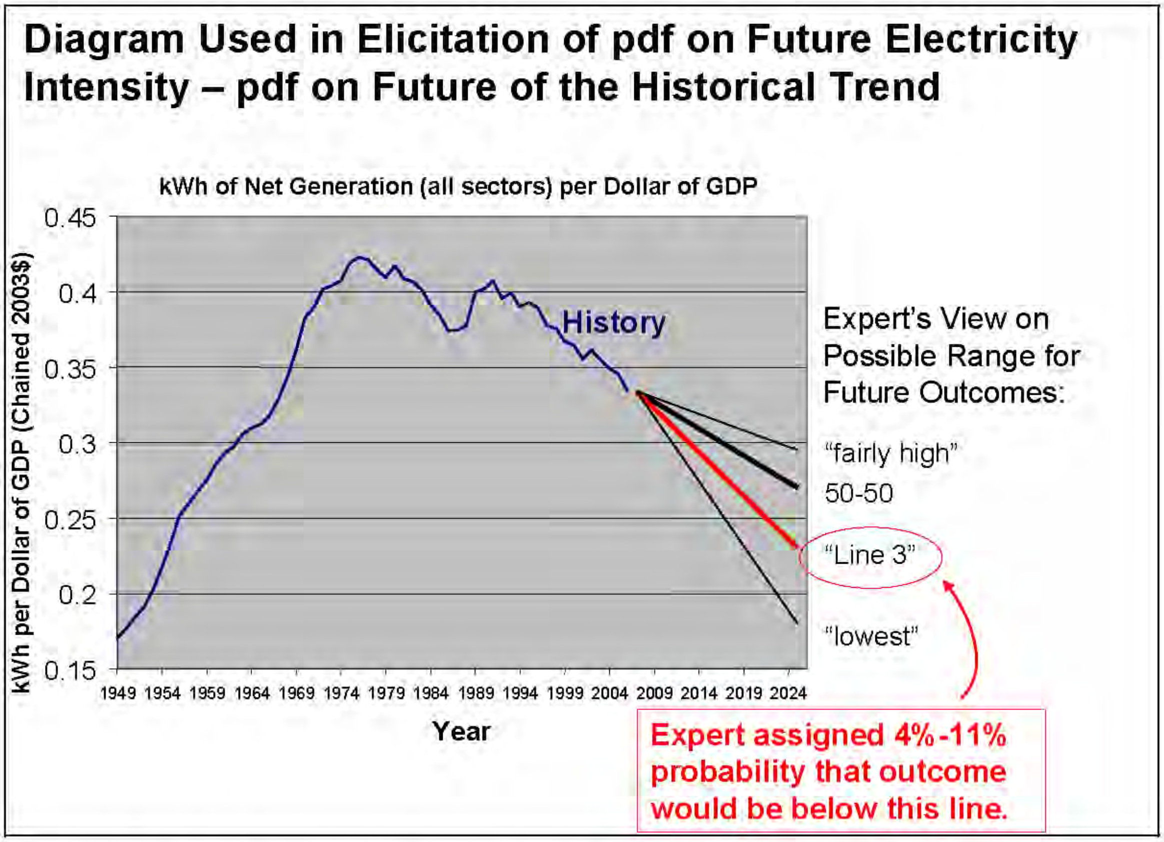

Figure 4: Elicited Probability Distribution of Future Electricity Intensity Alongside Historical Trends.

With this backdrop, a discrete probability distribution function was developed for future electricity intensities within the IRP planning horizon. First, Mr. Voytas ascertained what a "break-even" trajectory might look like on the above graph, where he would assign an equal 50% probability to either the improvement in electricity intensity exceeding or trailing this path. This is given by the black "50-50" line in Figure 4, and, incidentally, this line sits only slightly above the electricity path implied by the business-as-usual (BAU) scenario. Next, the expert established bounds on probable electricity intensity movements, concluding that a trajectory resulting in a 2026 intensity lower than roughly 0.30 kWh per chained 2003 dollar of GDP was extremely likely, and that a 2026 intensity below approximately 0.18 kWh per chained 2003 dollar of GDP was highly unlikely. CRA then presented the red "Line 3" adjacent to the upper, median, and lower trajectories, and elicited a probability ranging from 4% to 11% that the electricity intensity would be below "Line 3." Although the expert was initially unaware of this fact, "Line 3" lies slightly below the rate of improvement in electricity intensity necessary to achieve the full 20% reduction in electricity demand by 2030, as in the "transformed demand" scenario.

The next component of the "transformed demand" scenario was the envisioned surge in distributed generation (DG) applications, which could shave utility demand within the state of Missouri. After an extensive conversation, the expert established that the only source of significant DG-induced demand reductions would be through photovoltaic applications. Despite viewing solar technology as a major part of the ultimate solution towards the end of the century, Mr. Voytas did not foresee a significant penetration of photovoltaics within the planning horizon. According to his estimation, Missouri does not currently share the same popular enthusiasm for solar applications that other states like California enjoy. Then, with the help of visual diagrams in which probabilities were symbolized by areas within a circle, probabilities were elicited on the percentage of Missouri residential rooftops that would be equipped with photovoltaic modules by 2026. Mr. Voytas assigned 5% and 0.5% probabilities, respectively, to the events where more than 5% and more than 10%, respectively, of Missouri rooftops had solar modules.

Given the expert's independent assignment of probabilities to electricity intensity and distributed generation outcomes, Figure 5 below graphically portrays possible cumulative distribution functions (cdf) as a function of the 2026 electricity intensity.

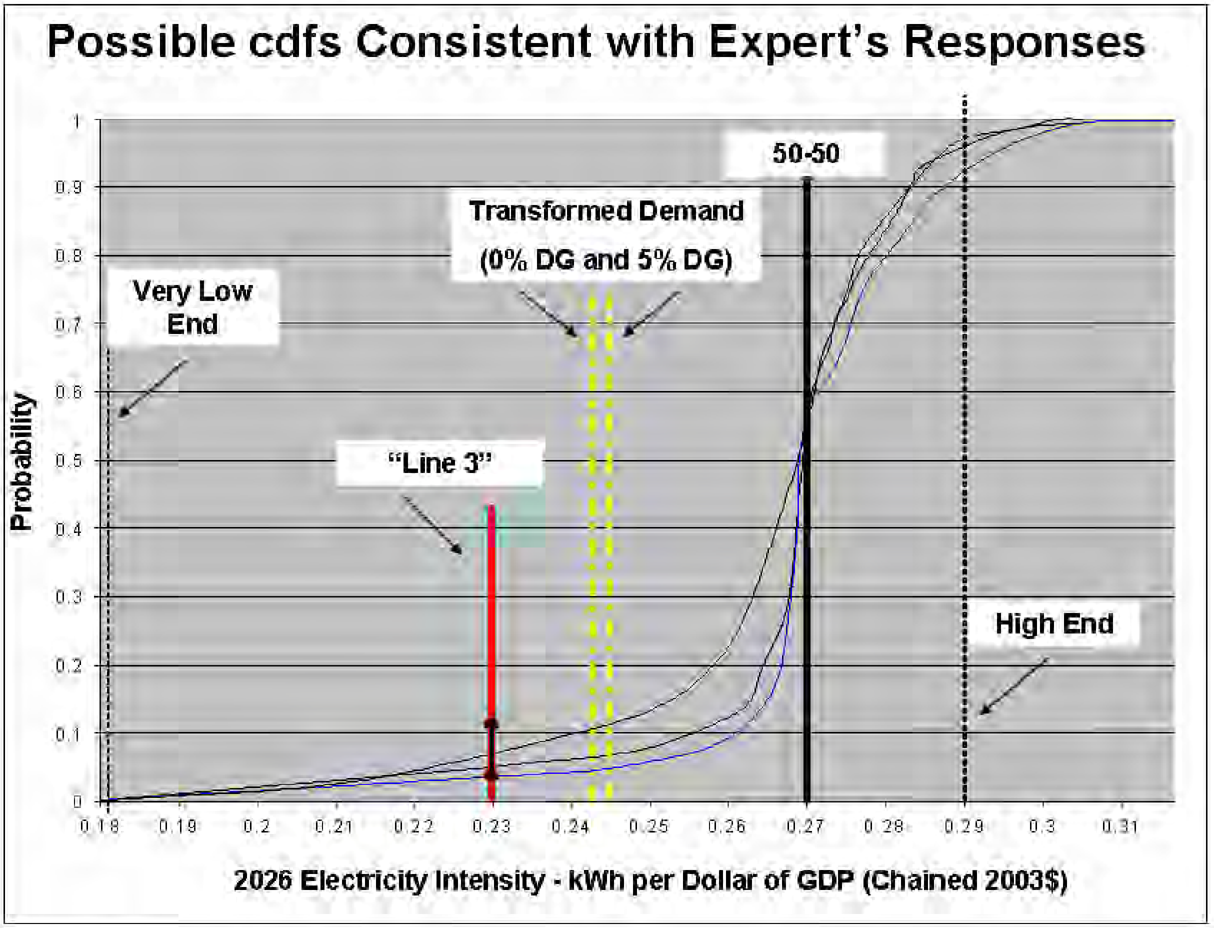

Figure 5: Cumulative Distribution Functions Representing Subjective Probabilities Consistent with Expert's Views.

The four vertical lines labeled "Very Low End," "Line 3," "50-50," and "High End" correspond to the 2026 electricity intensities given in Figure 4. The probabilities elicited from Mr. Voytas for these four outcomes effectively shaped potential cdfs, given by the three curved lines. The "transformed demand" scenario implies the 2026 intensity outcomes given by the two yellow verticals, with the leftmost line representing a 0% penetration of solar modules on Missouri rooftops and the rightmost line representing a 5% penetration.[3] It is the intersection of the cdfs (which were contoured by the subjective probabilities Mr. Voytas assigned to various intensity outcomes) and the yellow verticals (which represent the intensity that would result in the

[3] The incremental increase in electricity intensity due to 5% of Missouri rooftops being equipped with solar modules was extrapolated based upon CRA best estimates of the potential solar capacity per residential rooftop, of the capacity factor of photovoltaic modules, and U.S. Census data of the number of residential households in Missouri.

"transformed demand" scenario under two probable sets of distributed generation assumptions) that determine the probabilities that should be assigned to the "base case" and "transformed demand" scenarios. Notwithstanding the fact that Mr. Voytas assigned only 5% probability to the 5% penetration case, Figure 5 reveals that the incremental improvement in electricity intensity is minor (around 0.0025 kWh per chained 2003 dollar of GDP). As a result, even if one were to assume that the 5% penetration case were to occur with absolute certainty, the additional probability that it would contribute to the "transformed demand" scenario is very small.[4] In the end, the expert agreed that a probability of 7% was justified for the "transformed demand" case, with the remaining 93% slotted for the "base load" growth case (see Figure 6 below).

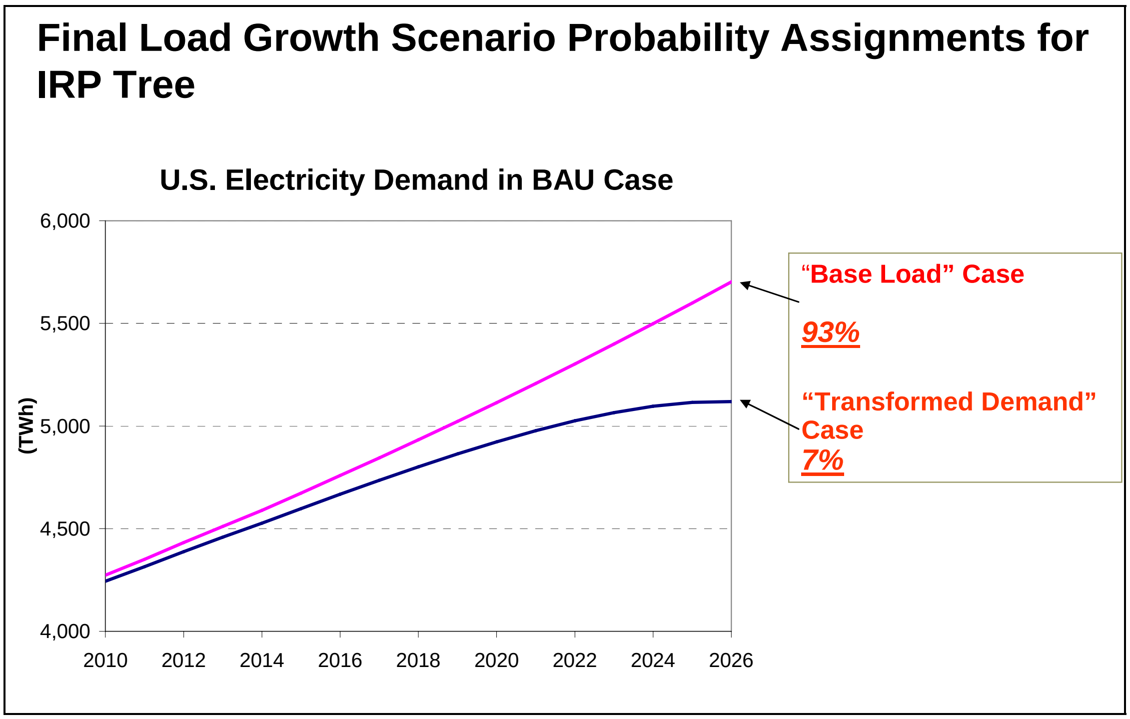

Figure 6: Final Load Growth Scenario Probability Assignments.

The model outputs for Eastern Missouri[5] load forecasts for each scenario in the probability tree are given below in Figure 7.[6] Of note is the lack of a scenario projecting Eastern

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[4] Given the curvature of the cumulative distribution functions in Figure 5, the maximum rise in probability over the range bracketed by the 0% DG and 5% DG vertical lines appears to be no larger than approximately 2%.

[5] See Table B - 1 in 4 CSR 240-22.030 Appendix C for a data table of electricity demand in Eastern Missouri.

Missouri demand levels greater than those in the BAU case through the majority of the planning horizon. Indeed, in developing the scenario tree, AmerenUE cultivated a world view with demand growing at rates slower than BAU forecasts over the IRP modeling horizon. Given this particular scenario tree, the principal objective that still drives the creation of build plans is how to best assure adequate reliability. In turn, the risk-averse stance would be to determine, out of all of the worlds one surmises might evolve in the next 20 to 25 years, the scenario that features the highest load growth in AmerenUE's service territory. It is around this highest-demand scenario that AmerenUE should develop candidate resource plans, and, in this context, this happens to be the BAU case. Having ensured sufficient capacity reserves, AmerenUE can then turn to secondary (but also important) financial considerations in selecting the top resource plans for risk analysis.

[6] The Eastern Missouri (EMO) NEEM region includes units outside of AmerenUE. As such, AmerenUE utilized the annual percentage change in demand and applied this number to its current electricity demand. Table B - 2 of 4 CSR 240-22.030 Appendix C lists the percentage changes in demand from the BAU case for each scenario.

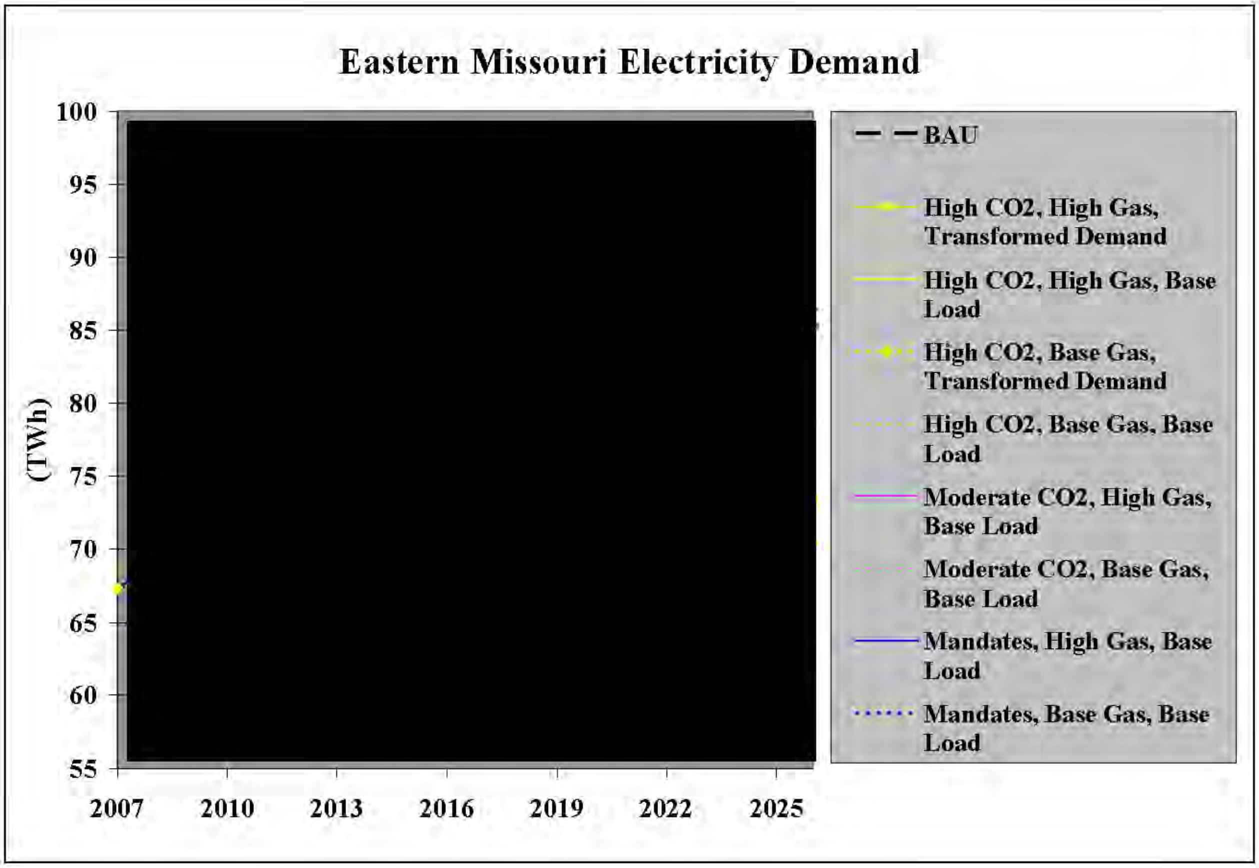


Figure 7: Eastern Missouri Electricity Demand (TWh).

Building around the BAU provides additional benefits, particularly in managing the risk asymmetry inherent to any resource planning process. Given the objectives of a public utility, the risks to reliability of a capacity shortage are considered a dominant concern, compared to the consequences of a temporary overbuild. Further, the mitigation of a capacity shortage situation is a slow process, given lead times to build new capacity. In contrast, if it becomes apparent that load may be growing less rapidly than planned for, new capacity projects may be more quickly slowed. The question then arises as to how AmerenUE can effectively manage the risks of building excess capacity. The range of integrated scenarios demonstrating lower demand growth rates provides a context in which to answer this question. Especially when considering that AmerenUE is not projecting an urgent need for new capacity, it is much easier to delay than to speed up construction plans, if loads in AmerenUE's service territory indeed fall below the BAU projections used for capacity planning. Furthermore, if AmerenUE is vigilant in developing contingency plans that account for these lower demand levels, then the costs of postponing or suspending new builds can be minimized up front.

Thus, building alternative resource plans upon the world view of BAU demand forecasts most adequately addresses the foremost concern of reliability. The construction of a probability tree whose scenarios all featured lower demand growth rates obviated the need for a "high-growth" case to bracket the base case load forecast. Moreover, if scenarios reflecting relatively lower demand levels serve as a context for the probabilistic evaluation of alternative resource plans, then AmerenUE can cost-effectively manage any potential overbuilds.

4 CSR 240-22.030 (8) (A)

(8) Reporting Requirements. To demonstrate compliance with the provisions of this rule, and pursuant to the requirements of 4 CSR 240-22.080, the utility shall prepare a report that contains at least the following information:

(A) For each major class specified in subsection (1) (A), the utility shall provide plots of number of units, energy usage per unit and total class energy usage.

1. Plots shall be produced for the summer period (June through September), the remaining nonsummer months and the calendar year.

2. The plots shall cover the historical data base period and the forecast period of at least twenty (20) years.

A. The historical period shall include both actual and weather-normalized energy usage per unit and total class energy usage.

B. The plots for the forecast period shall show each end-use component of major class energy usage per unit and total class energy usage for the base-case forecast.

Figure (8)-1: Total employment (Ths., SA)

Figure (8)-2: Manufacturing employment (Ths., SA)

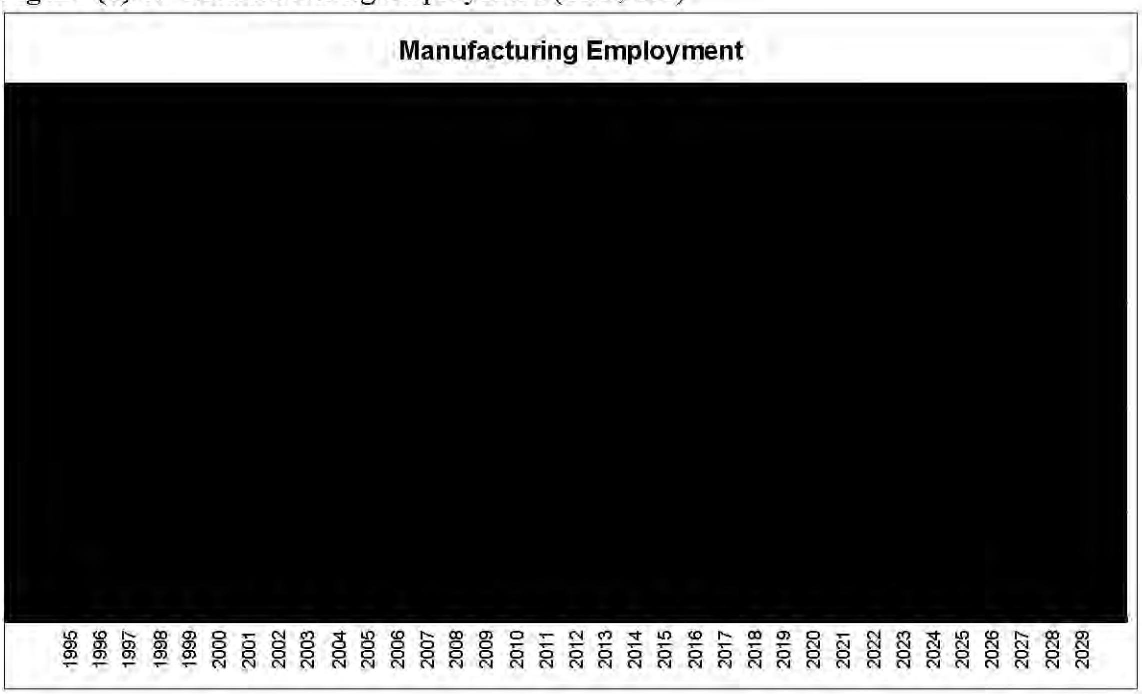


Figure (8)-3: Non-manufacturing employment (Ths., SA)

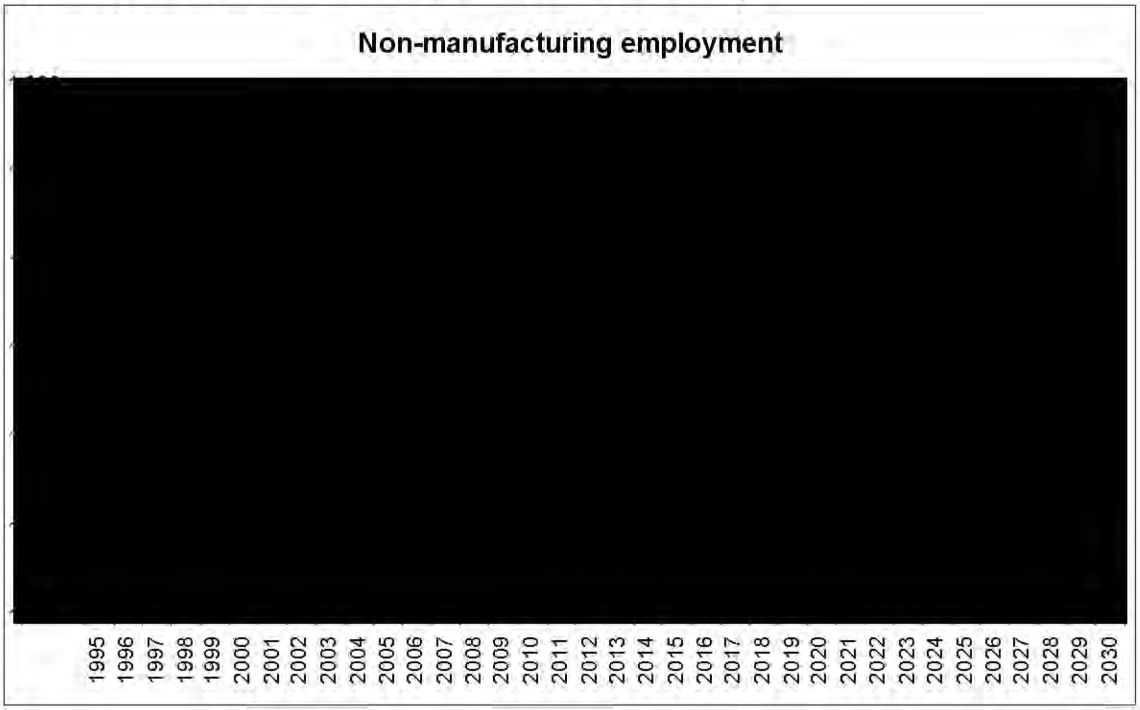


Figure (8)-4: Retail employment (Ths., SA)

Figure (8)-5: Total GDP (Mil. Chained 2000 $)

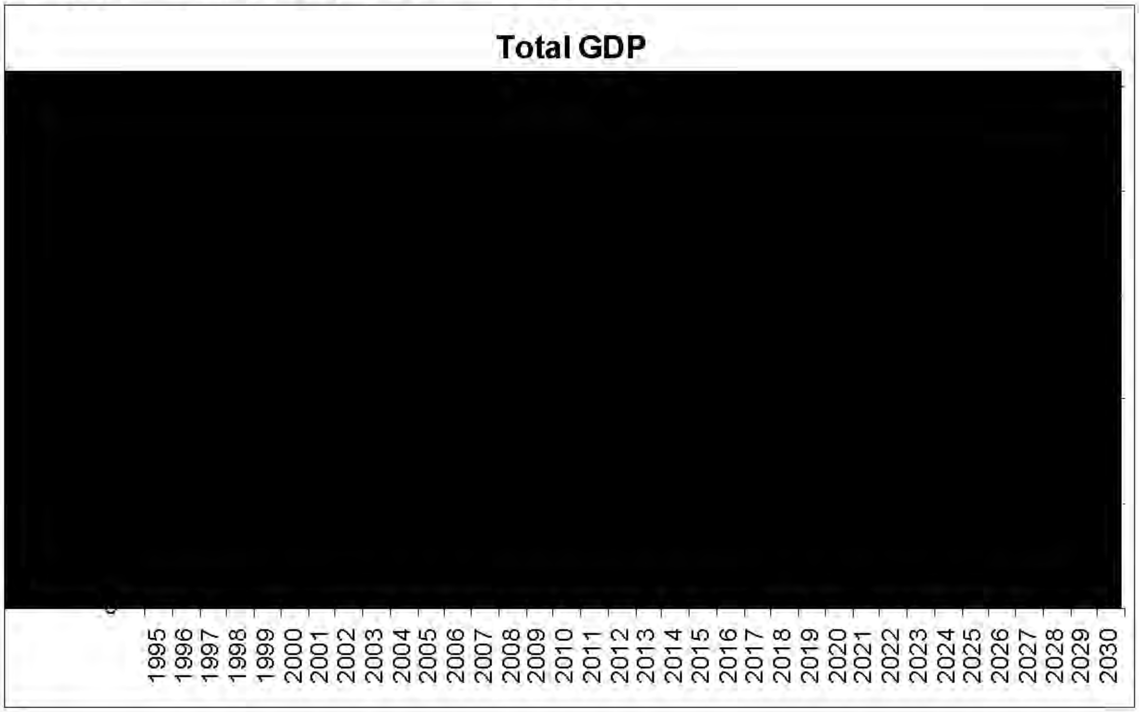


Figure (8)-6: Manufacturing GDP (Mil. Chained 2000 $)

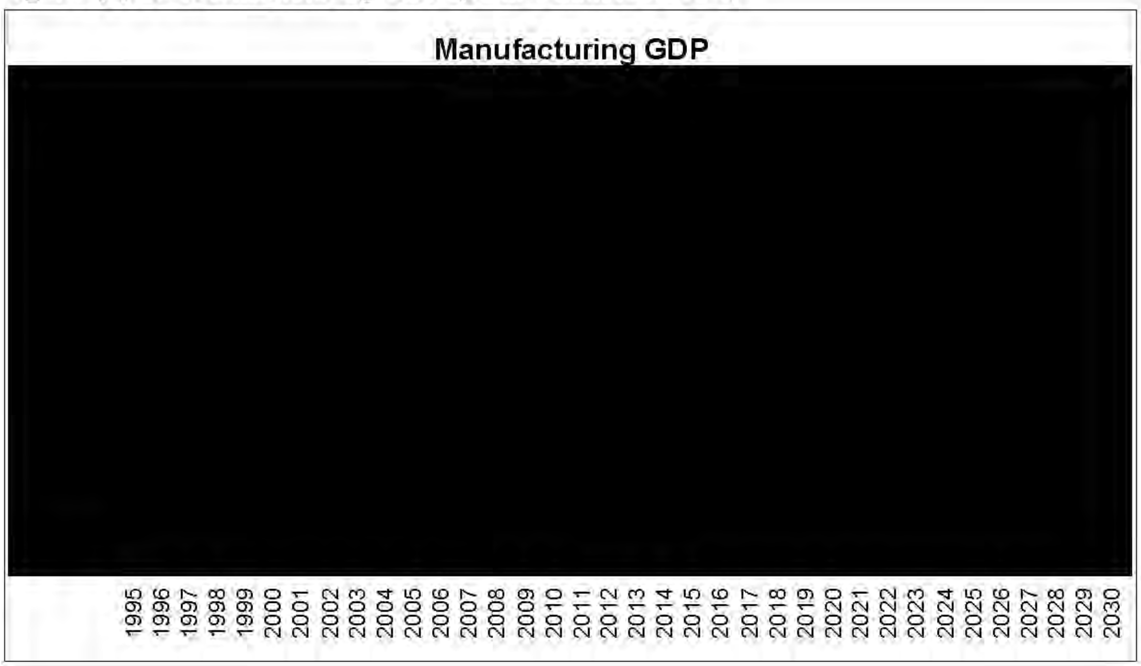


Figure (8)-7: Non-manufacturing GDP (Mil. Chained 2000 $)

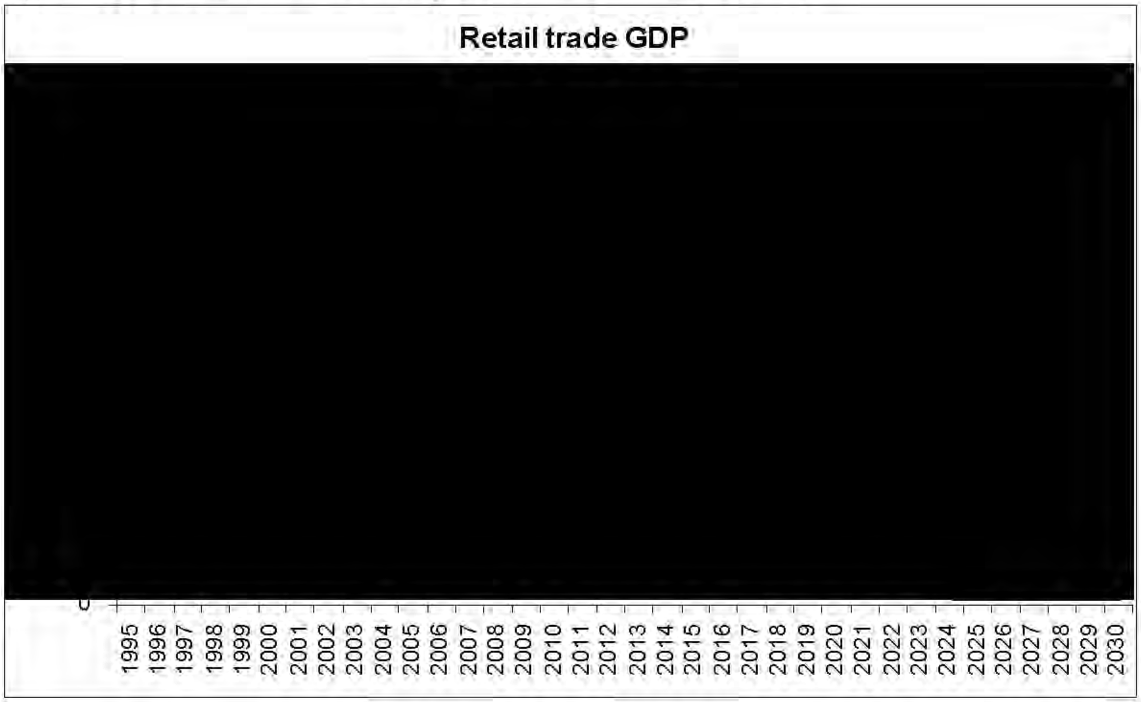


Figure (8)-8: Retail trade GDP (Mil. Chained 2000 $)

Figure (8)-9: Personal Income (Mil. $, SAAR)

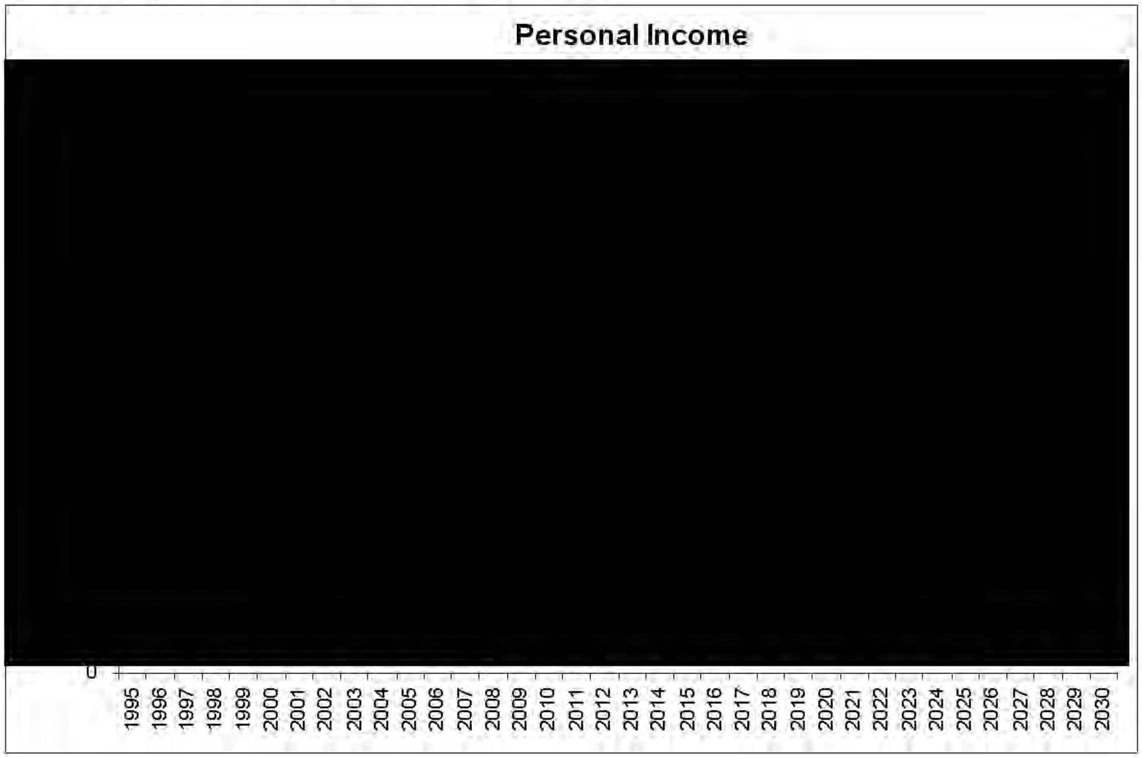


Figure (8)-10: Population (Ths., SA)

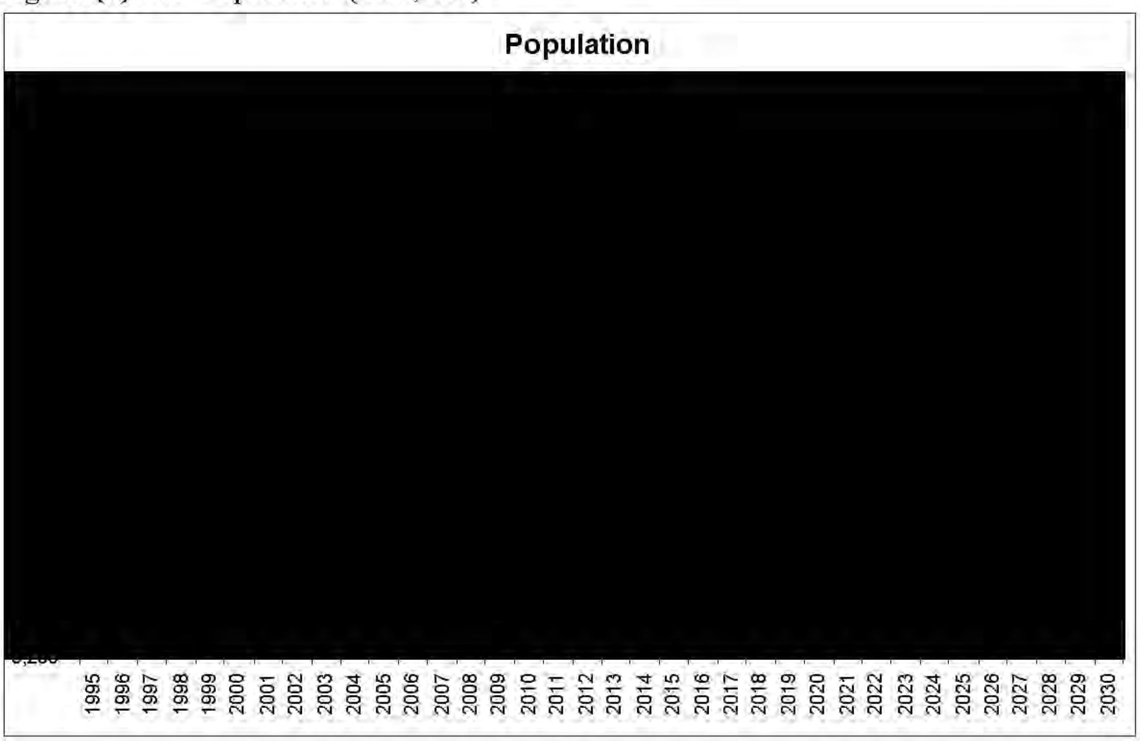


Figure (8)-11: Total Households (Ths., SA)

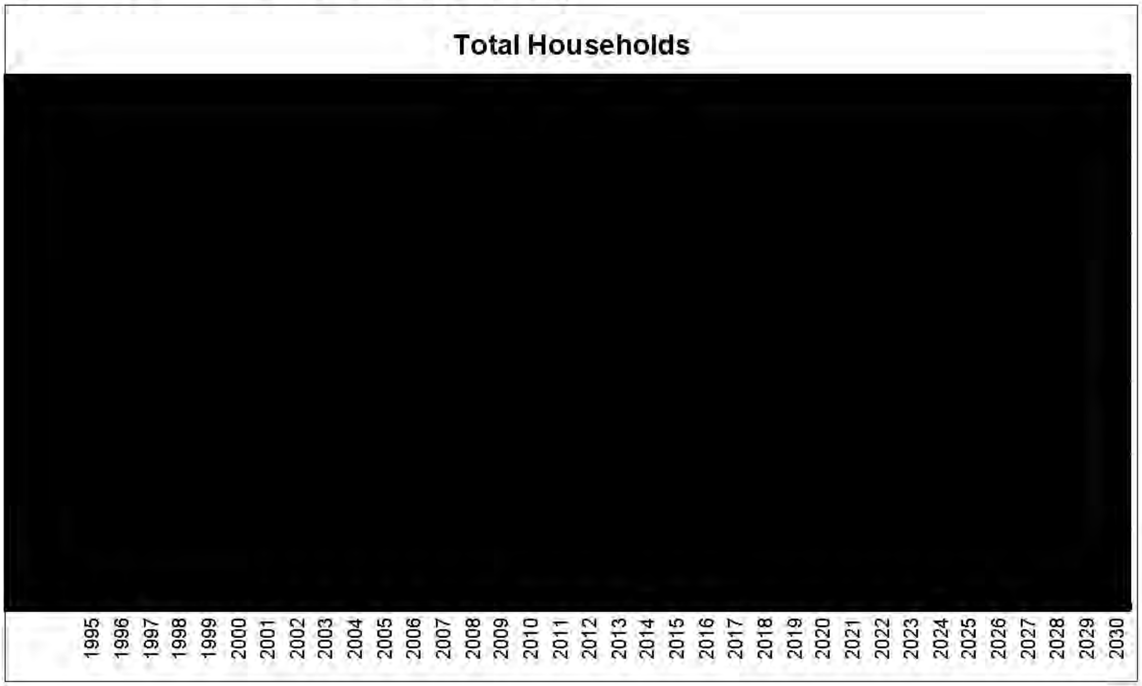


Figure (8)-12: Household Size (# of units, SAAR)

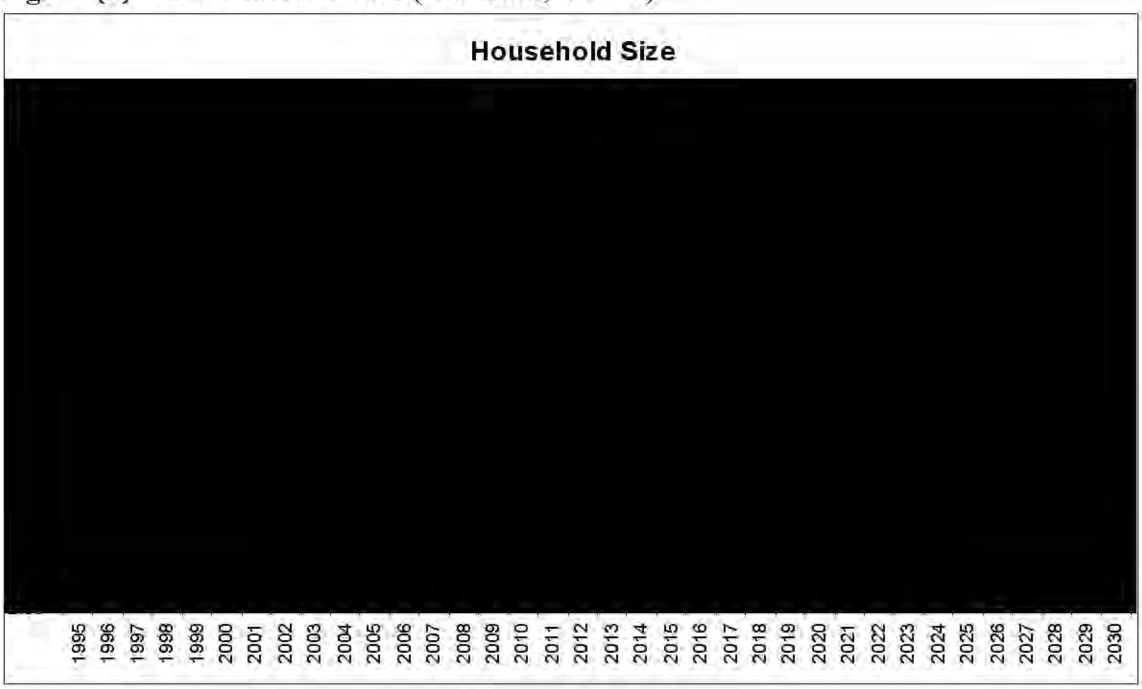


Figure (8)-13: Household income (Ths. $, SAAR)

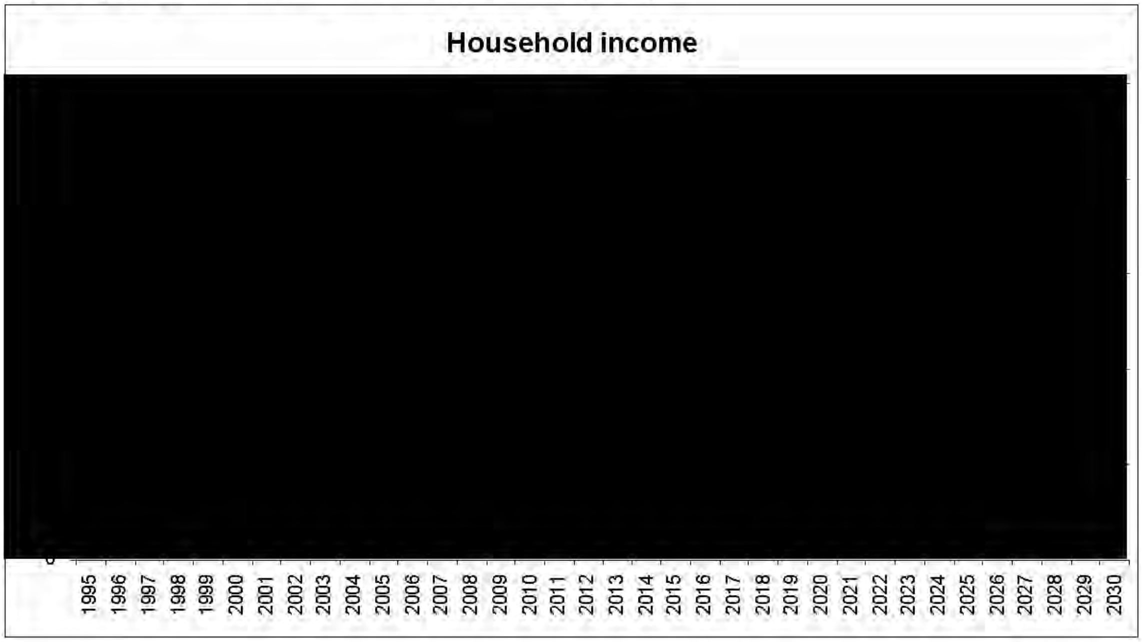


Figure (8)-14: Residential customers

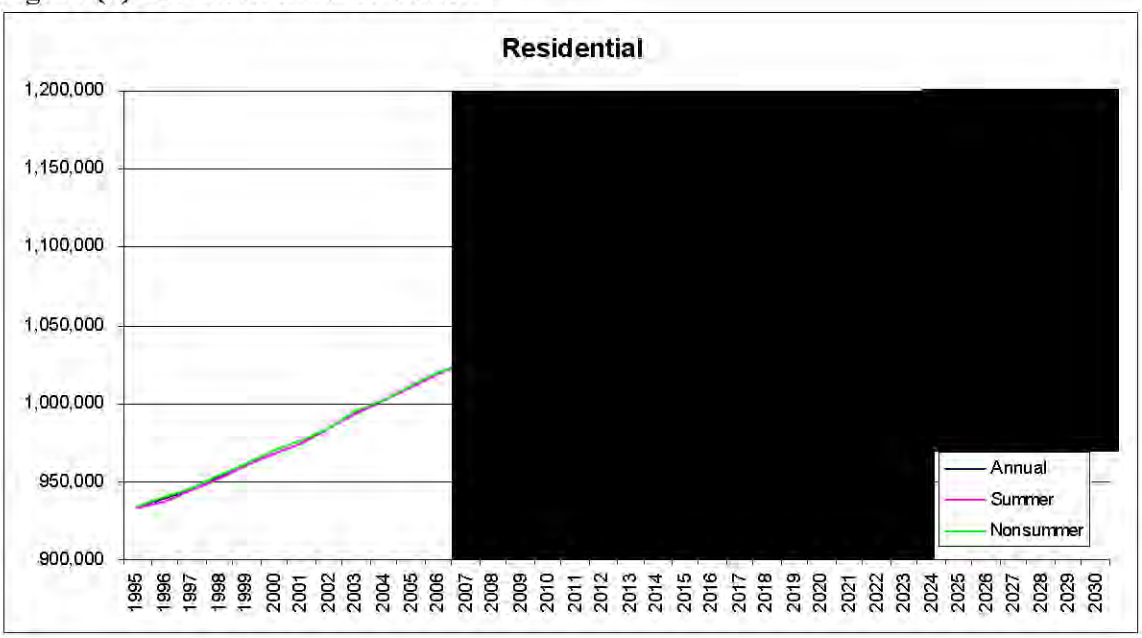


Figure (8)-15: Commercial SGS customers

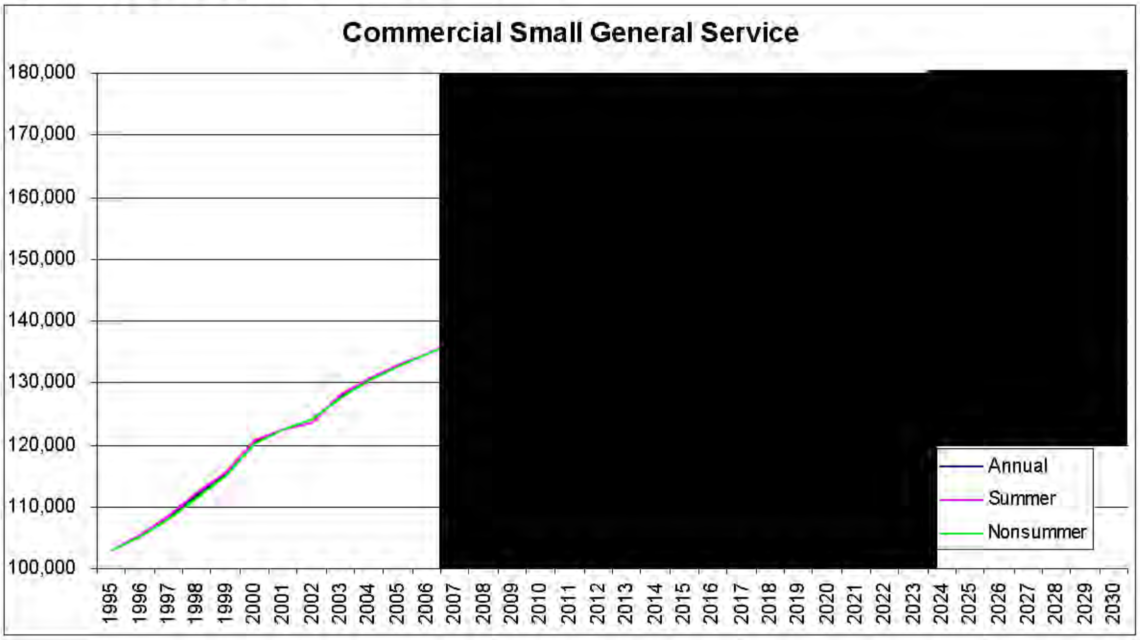


Figure (8)-16: Commercial LGS customers

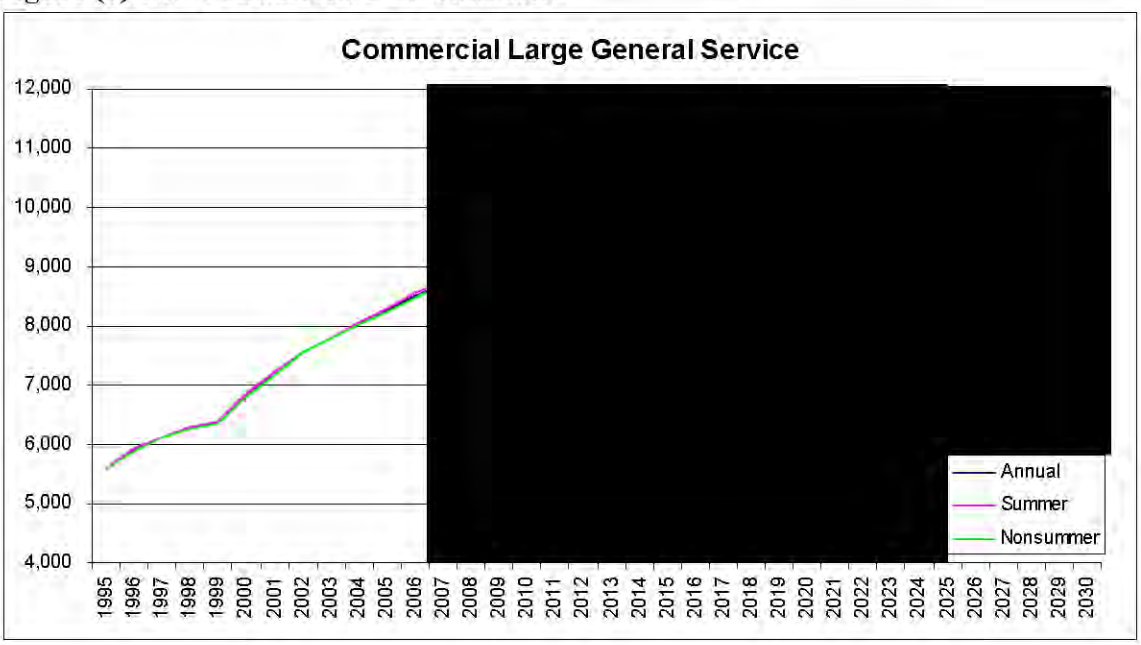


Figure (8)-17: Commercial SPS customers

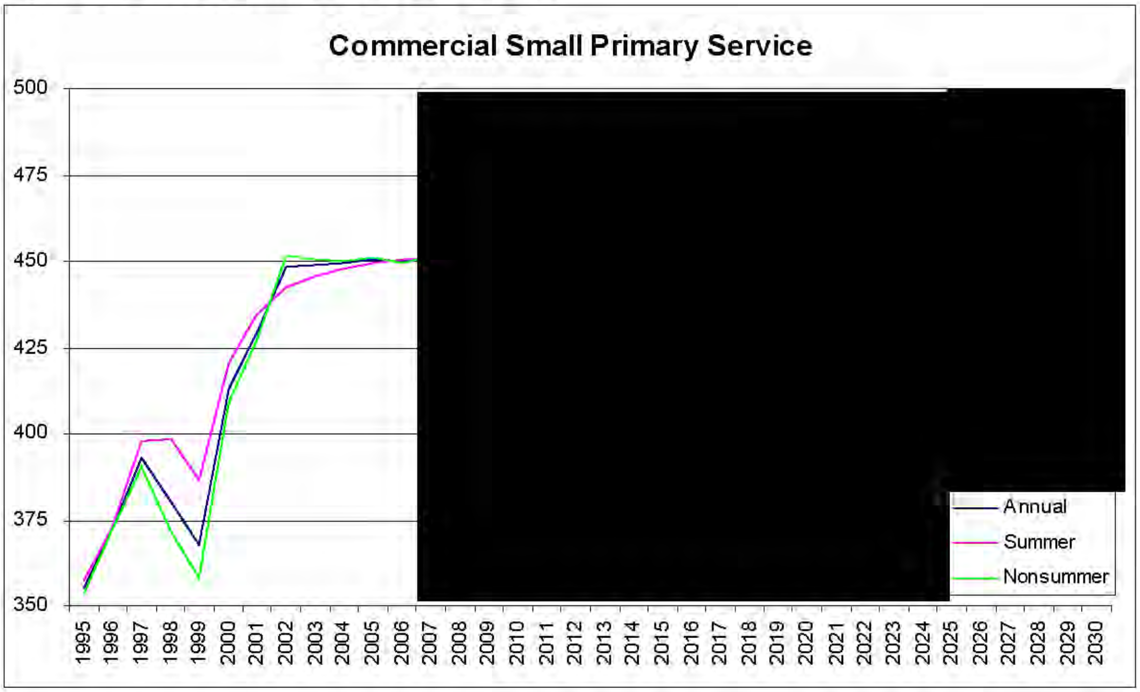


Figure (8)-18: Commercial LPS customers

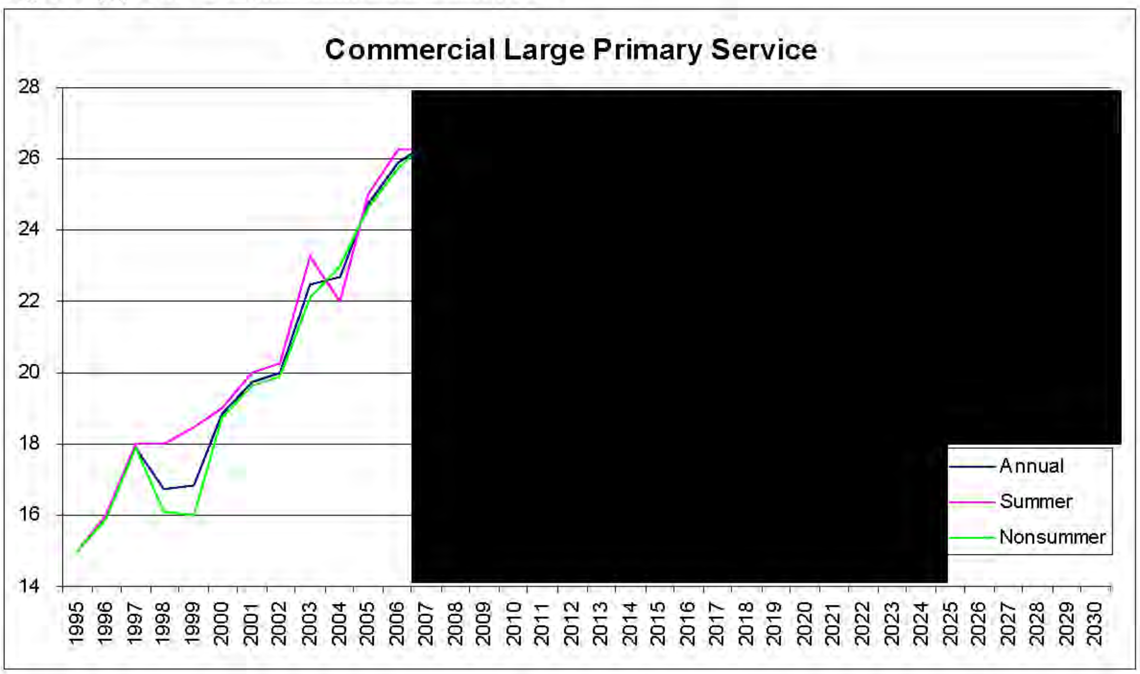


Figure (8)-19: Industrial SGS customers

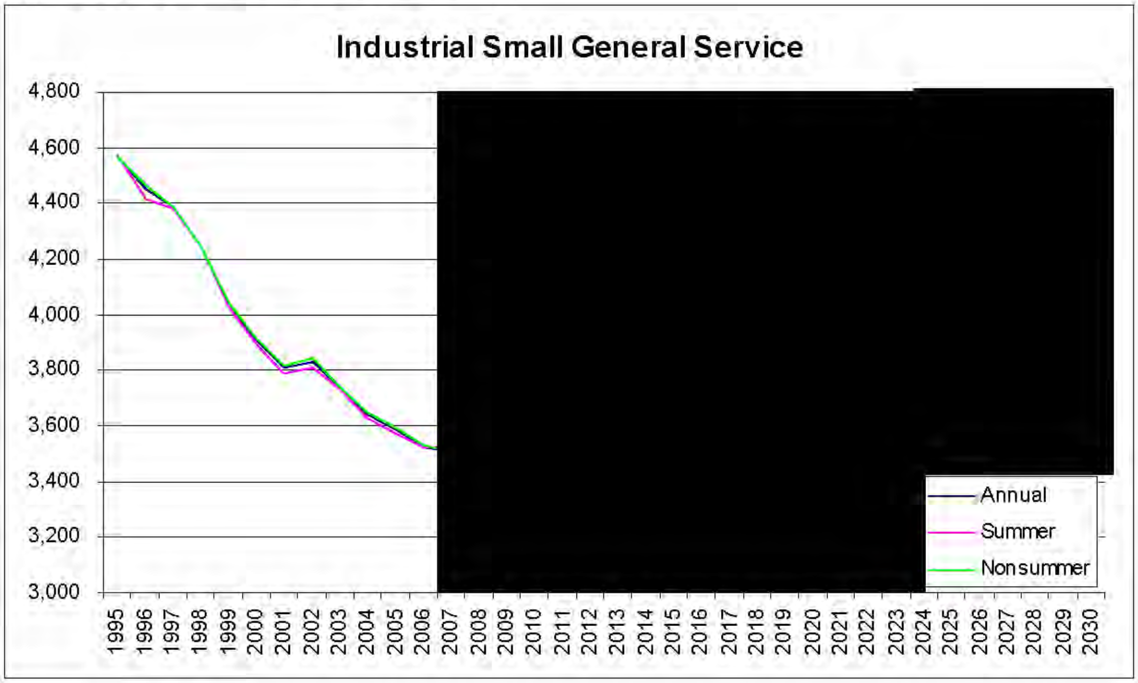


Figure (8)-20: Industrial LGS customers

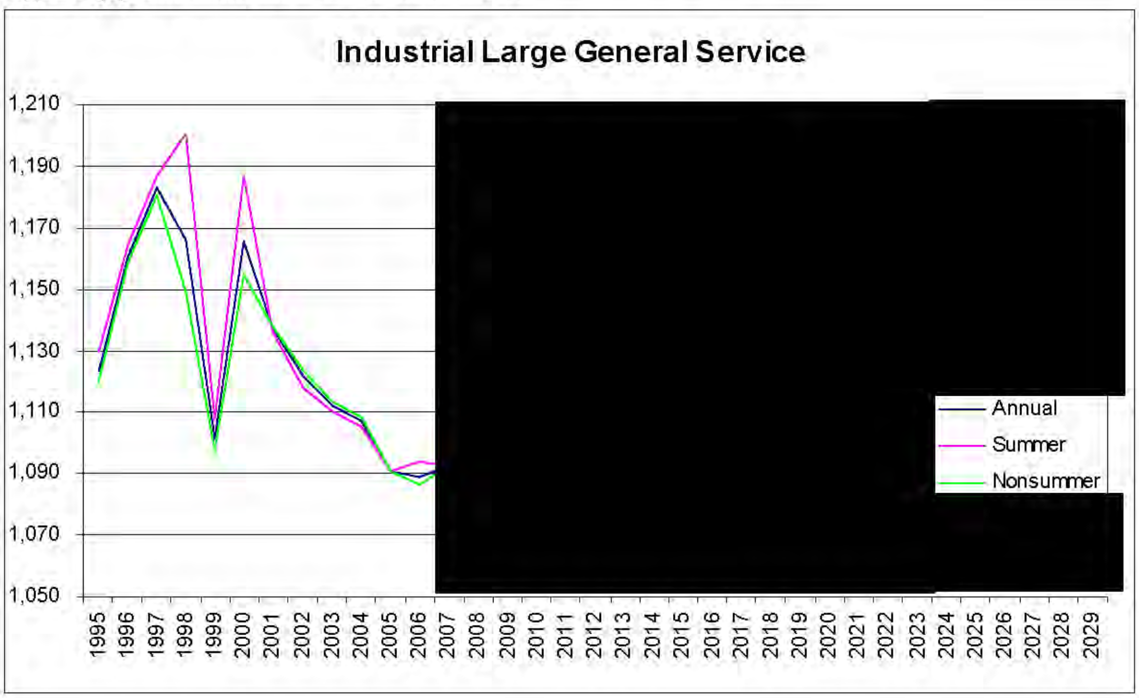


Figure (8)-21: Industrial SPS customers

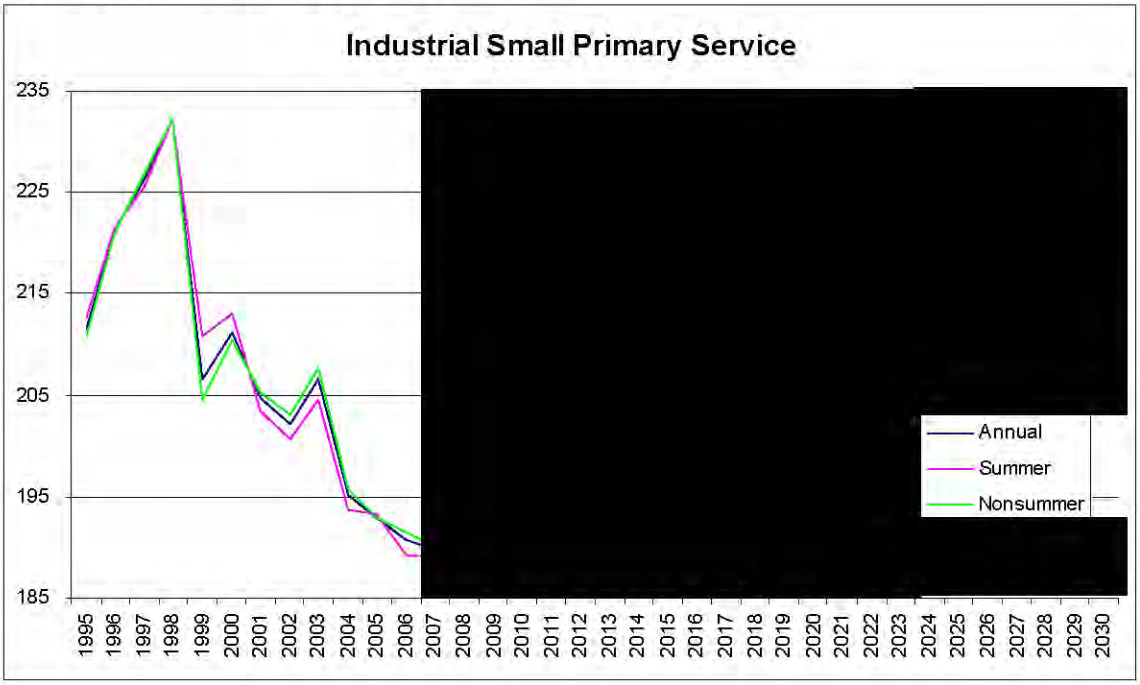


Figure (8)-22: Industrial LPS customers

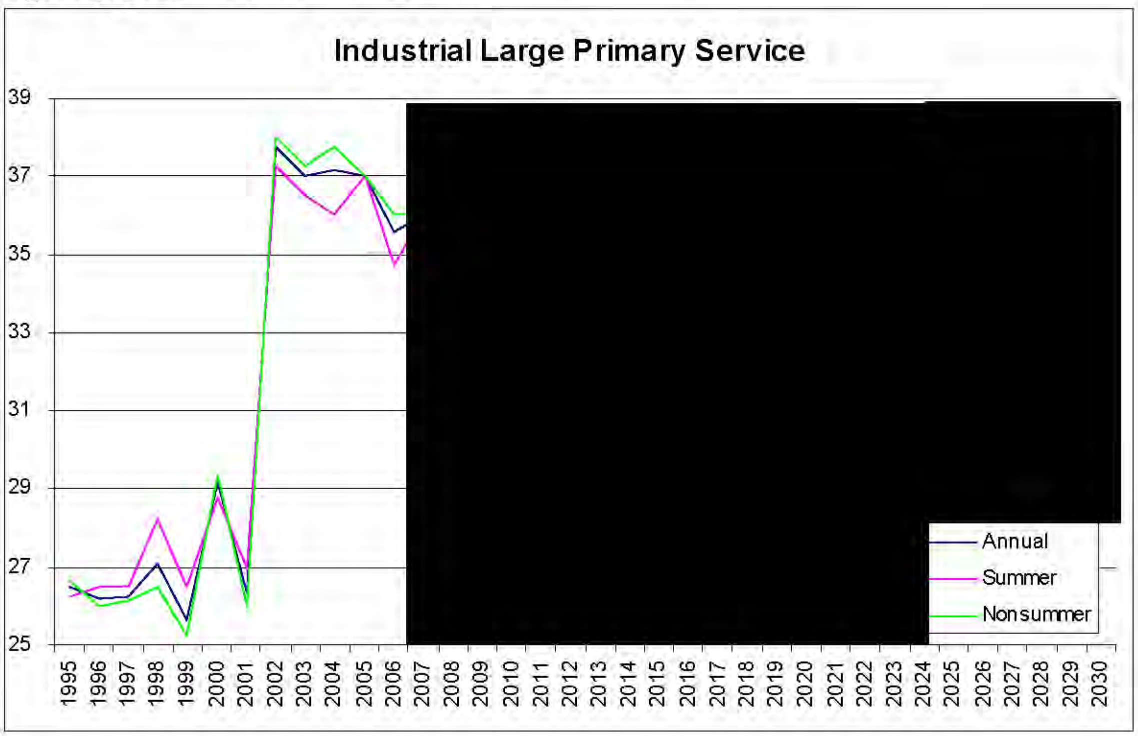


Figure (8)-23: DtD customers

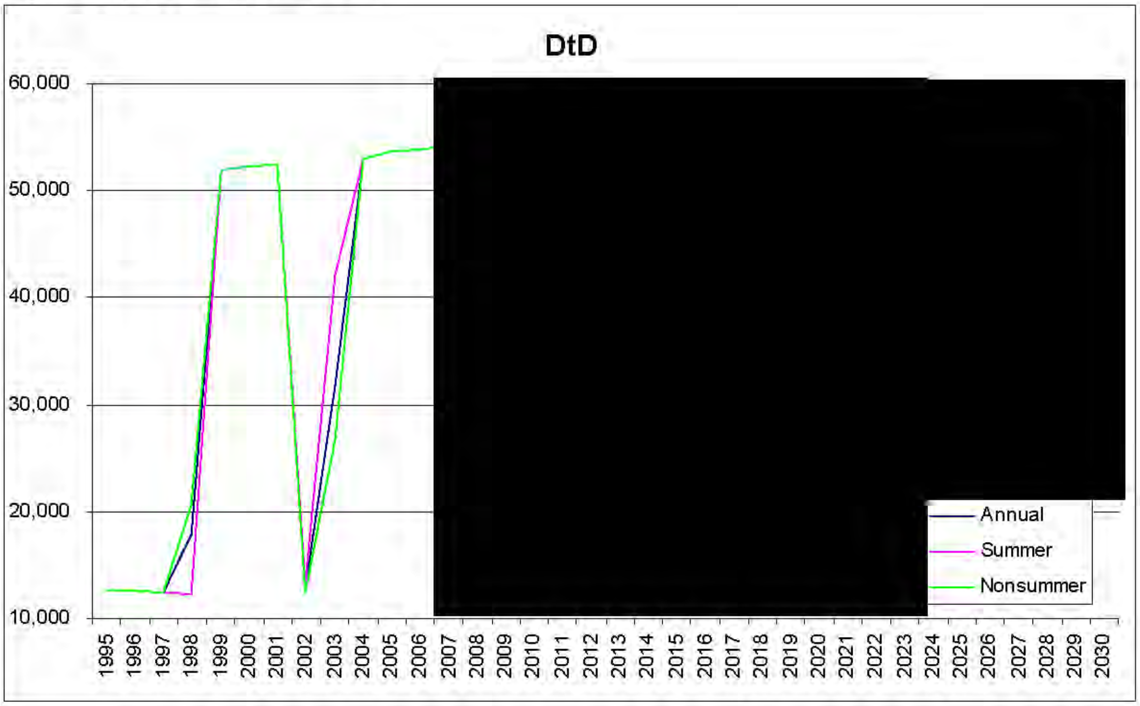


Figure (8)-24: SLPA customers

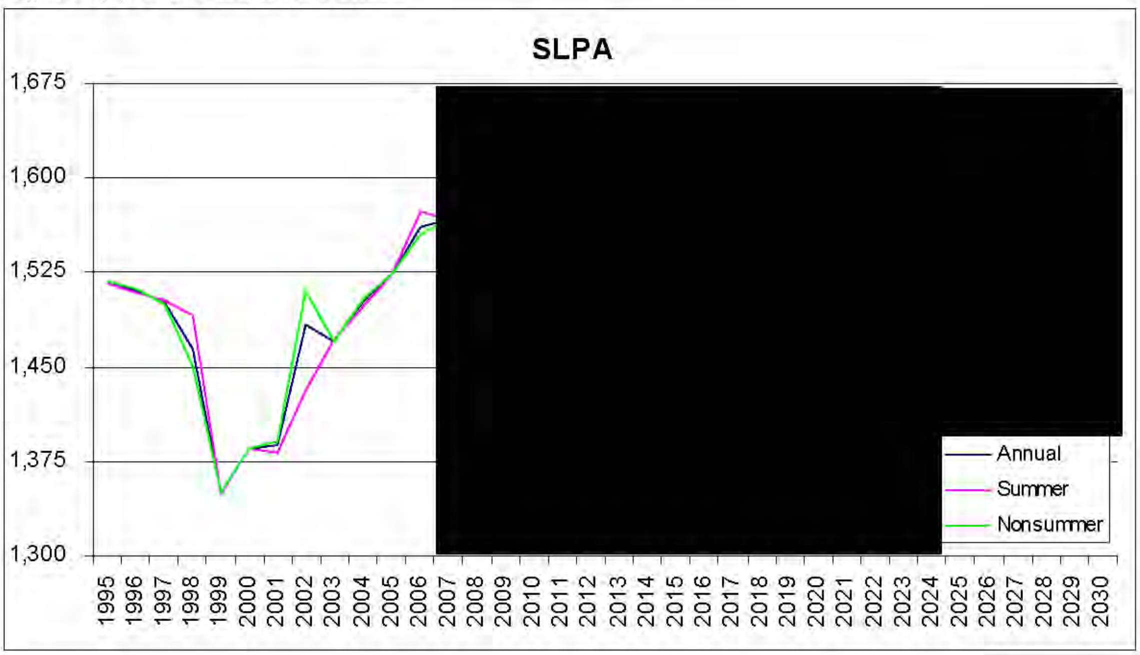


Figure (8)-25: Residential heating-use use-per-customer (Calendar month - MWh)

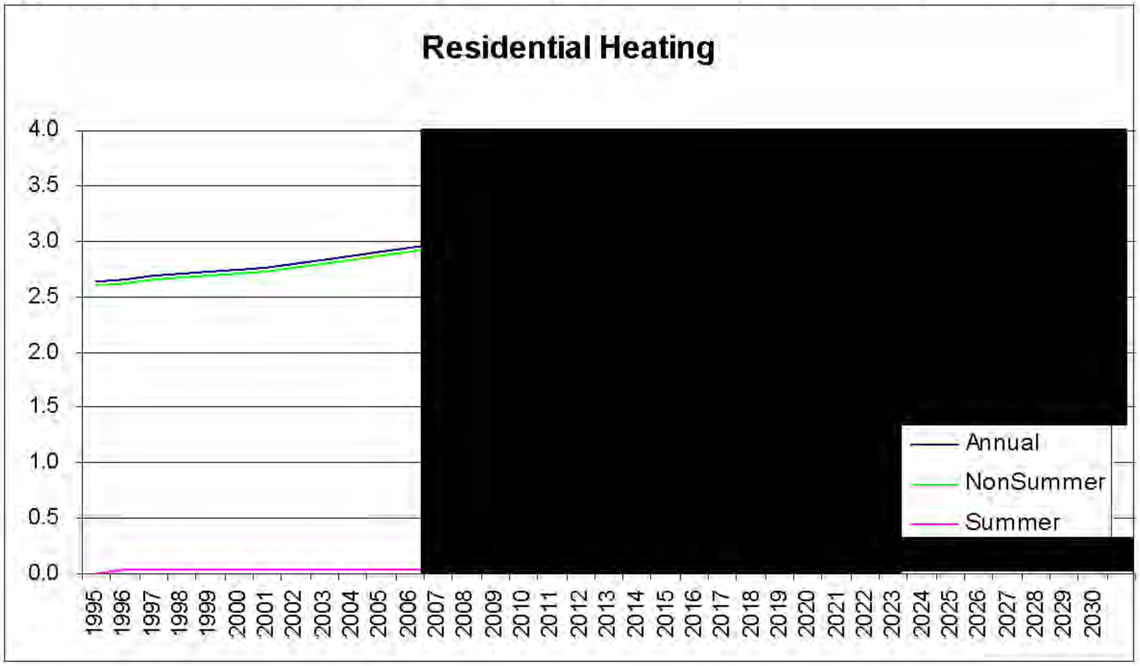


Figure (8)-26: Residential cooling-use use-per-customer (Calendar month - MWh)

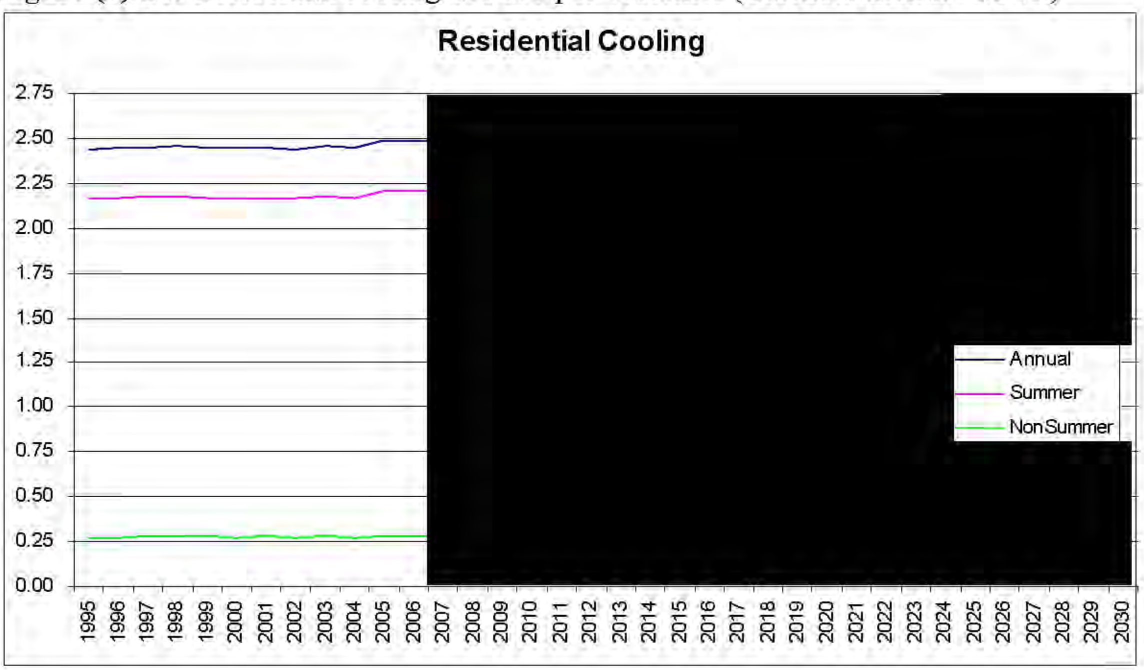


Figure (8)-27: Residential other use-per-customer (Calendar month - MWh)

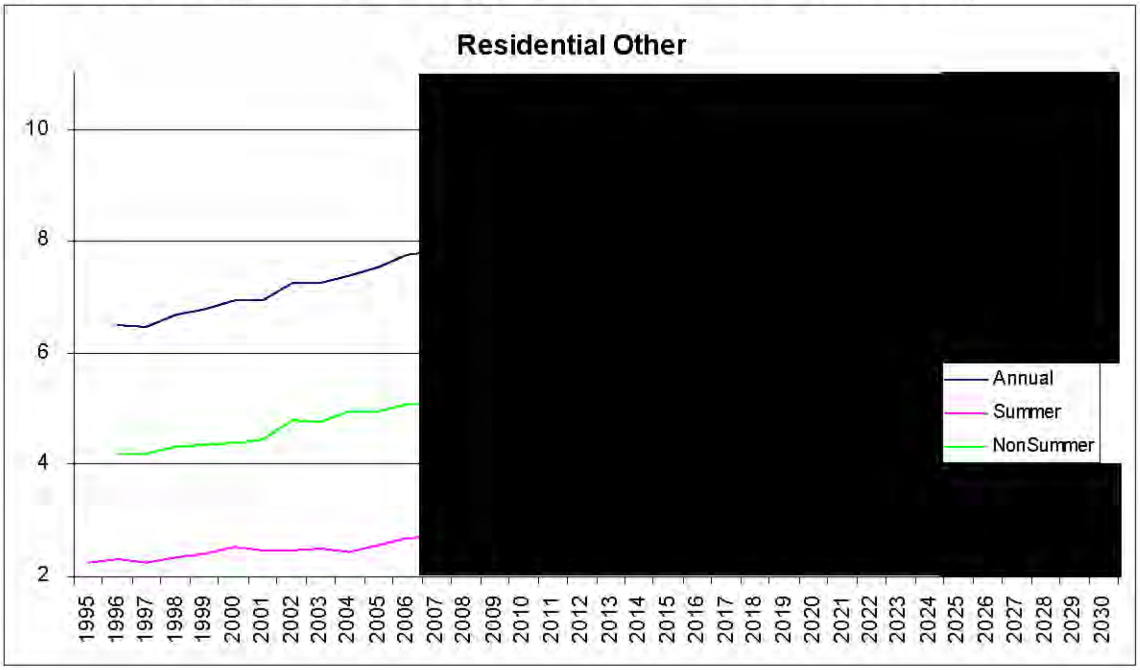


Figure (8)-28: Residential use-per-customer (Calendar month - MWh)

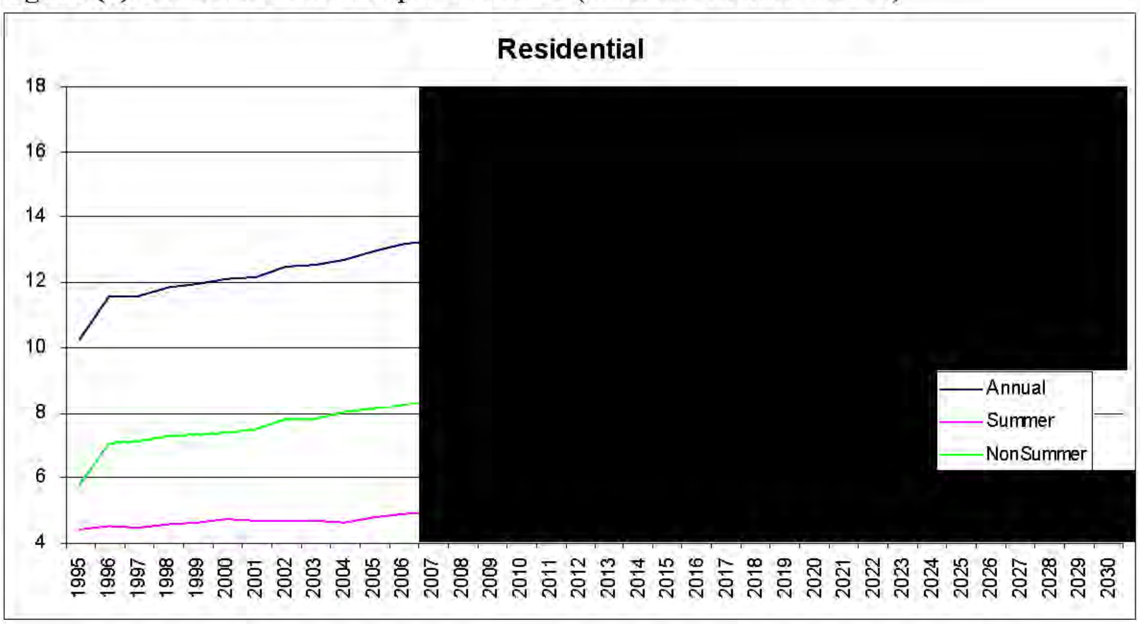


Figure (8)-29: Commercial SGS heating-use use-per-customer (Calendar month - MWh)

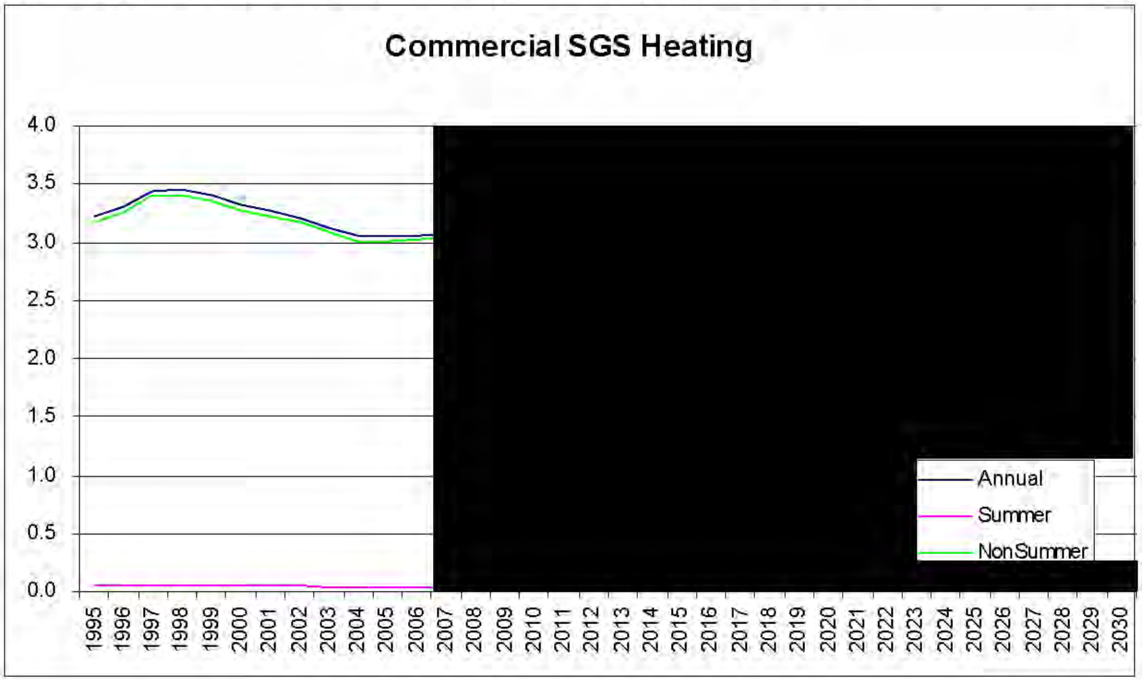


Figure (8)-30: Commercial SGS coooling-use use-per-customer(Calendar month - MWh)

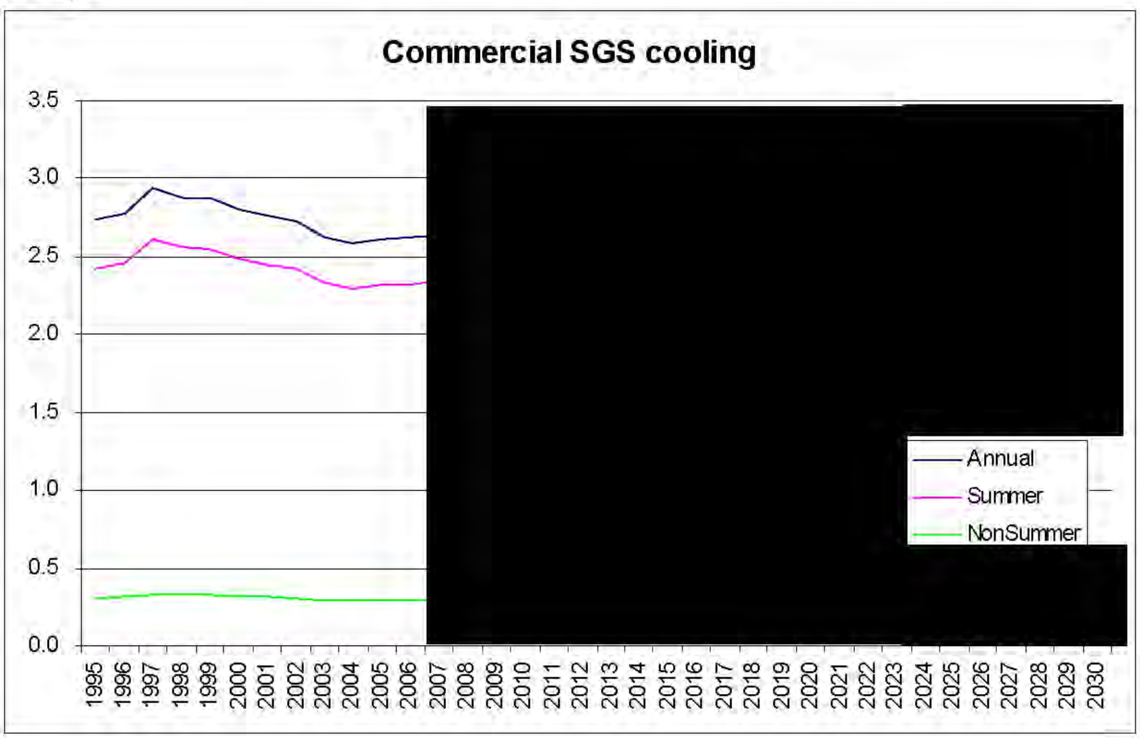
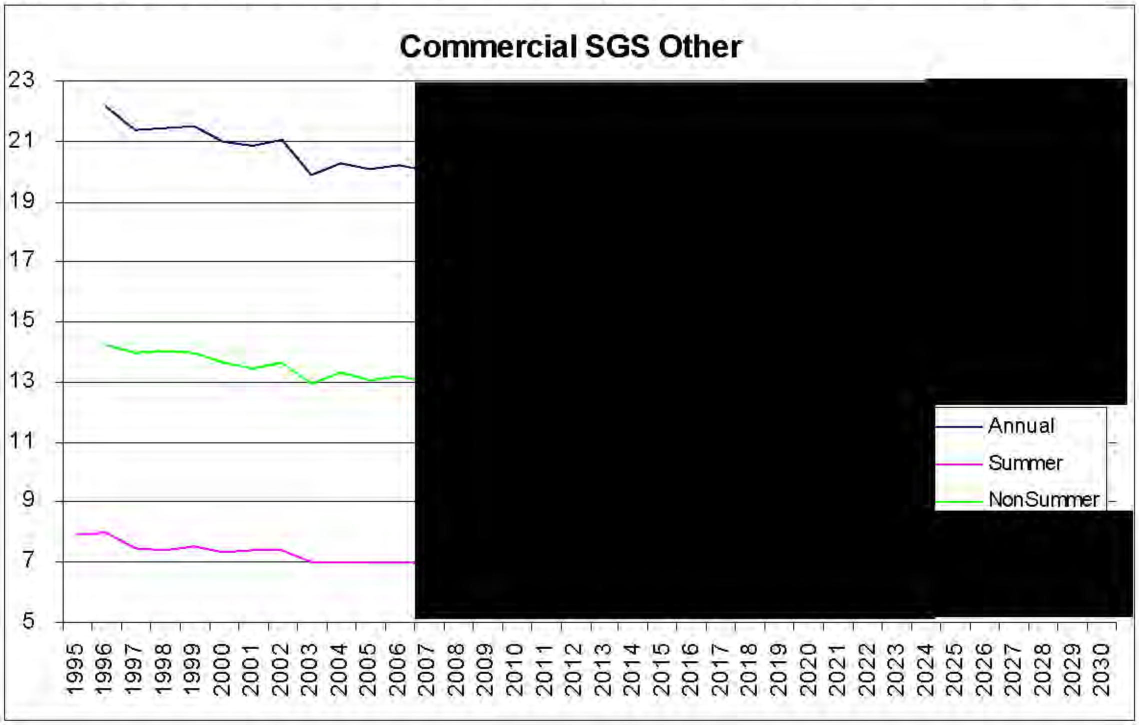
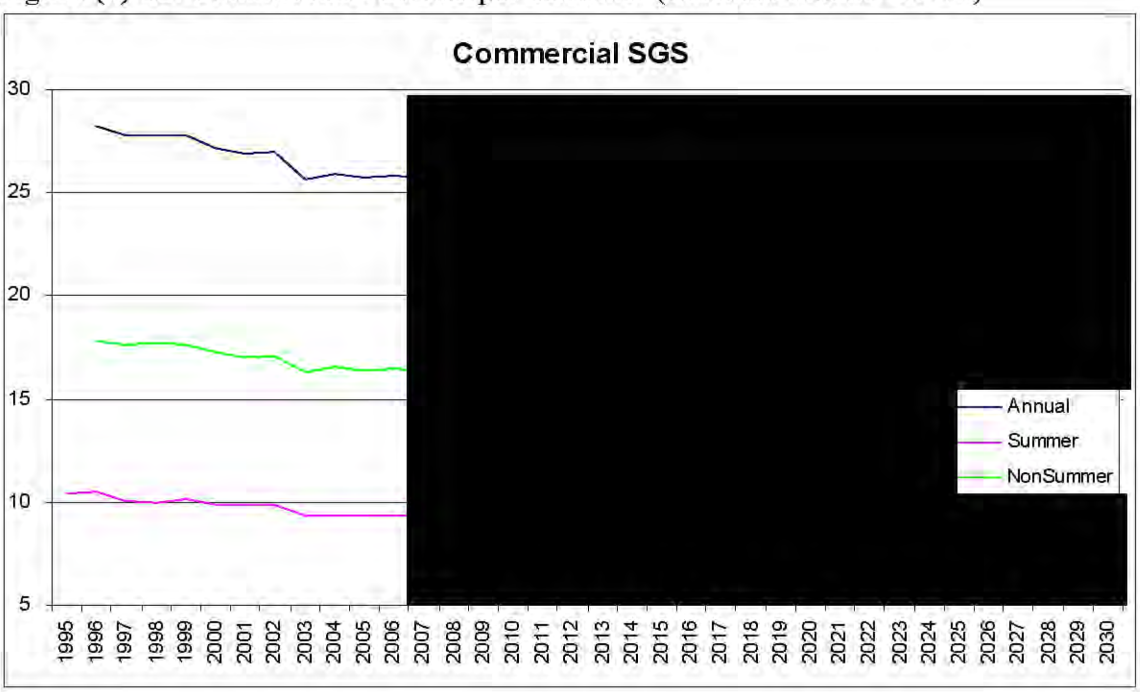


Figure (8)-31: Commercial SGS other-use use-per-customer (Calendar month - MWh)



[redacted]

Figure (8)-32: Commercial SGS use-per-customer (Calendar month - MWh)



[redacted]

Figure (8)-33: Commercial LGS heating-use use-per-customer (Calendar month - MWh)

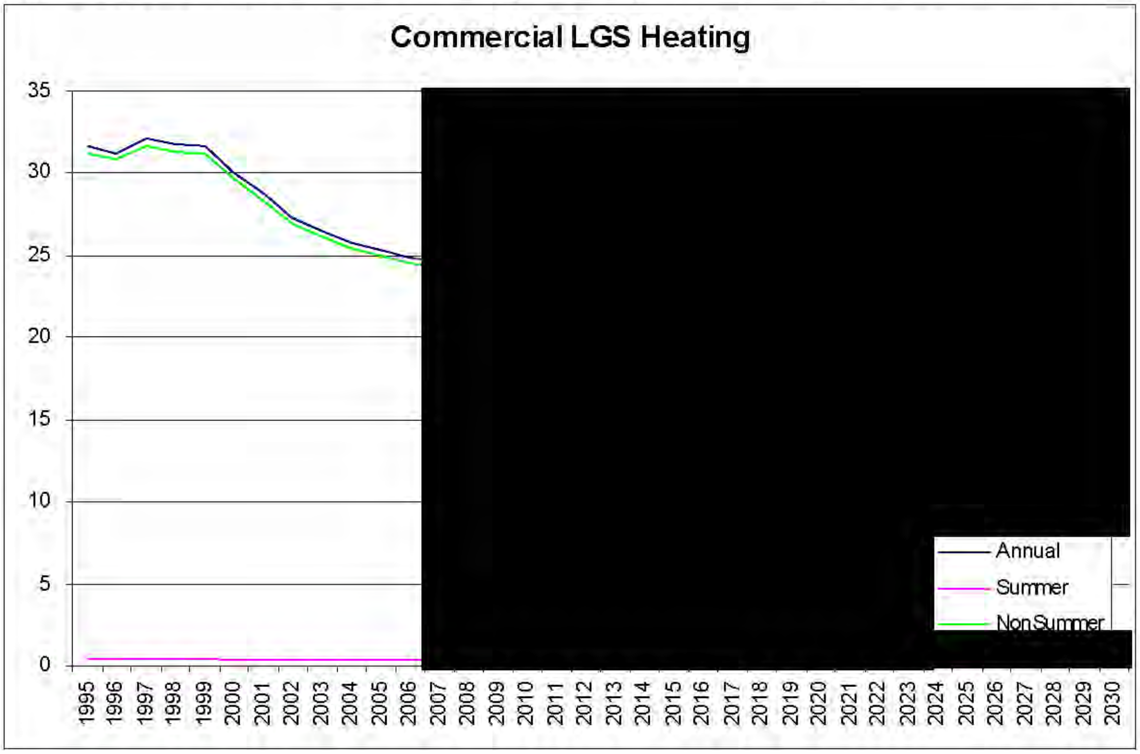


Figure (8)-34: Commercial LGS heating-use use-per-customer (Calendar month - MWh)

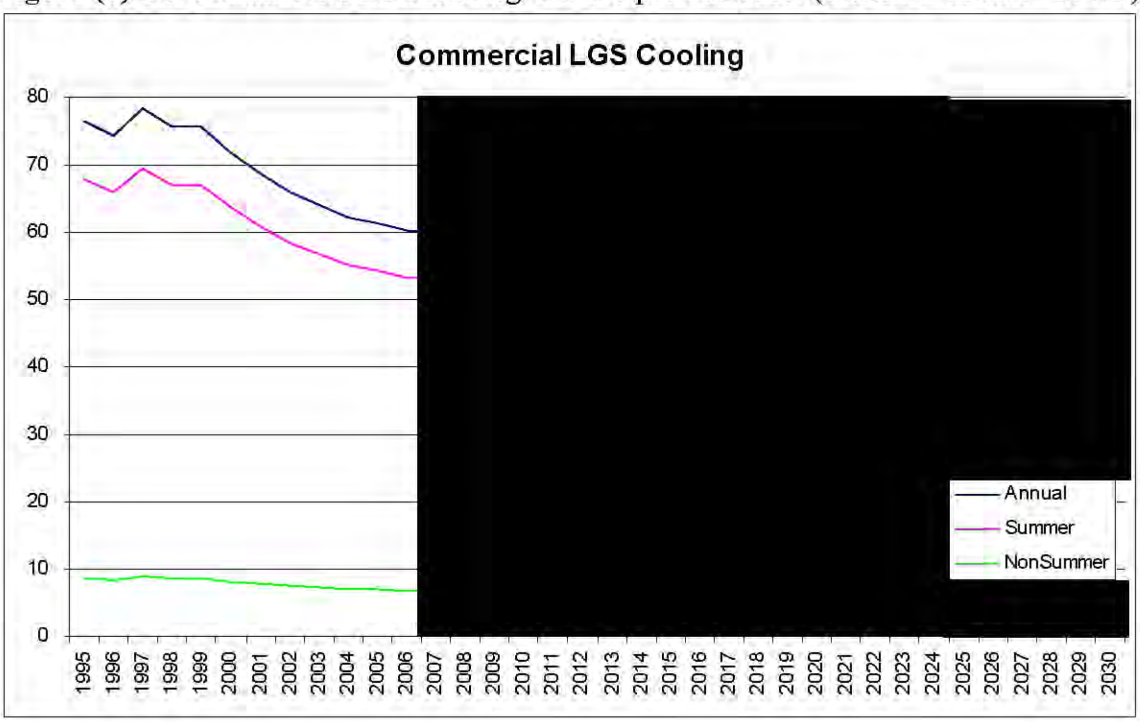


Figure (8)-35: Commercial LGS other-use use-per-customer (Calendar month - MWh)

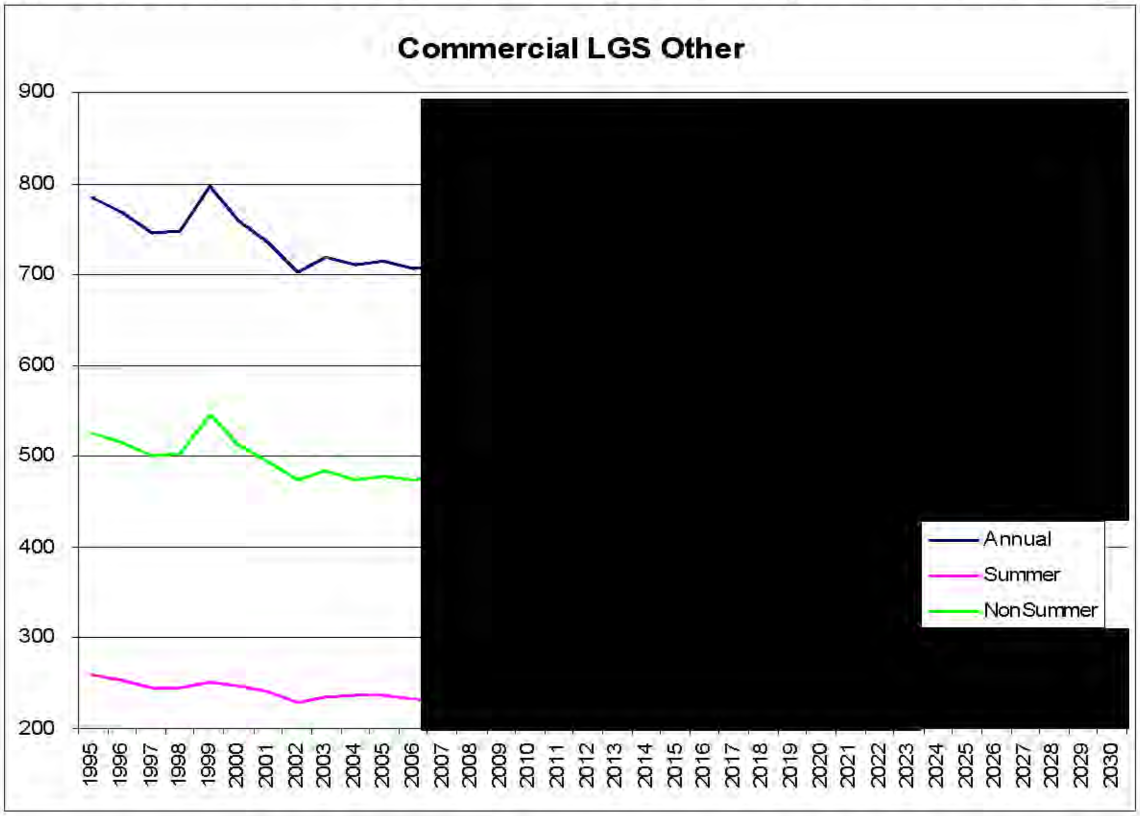


Figure (8)-36: Commercial LGS use-per-customer (Calendar month - MWh)

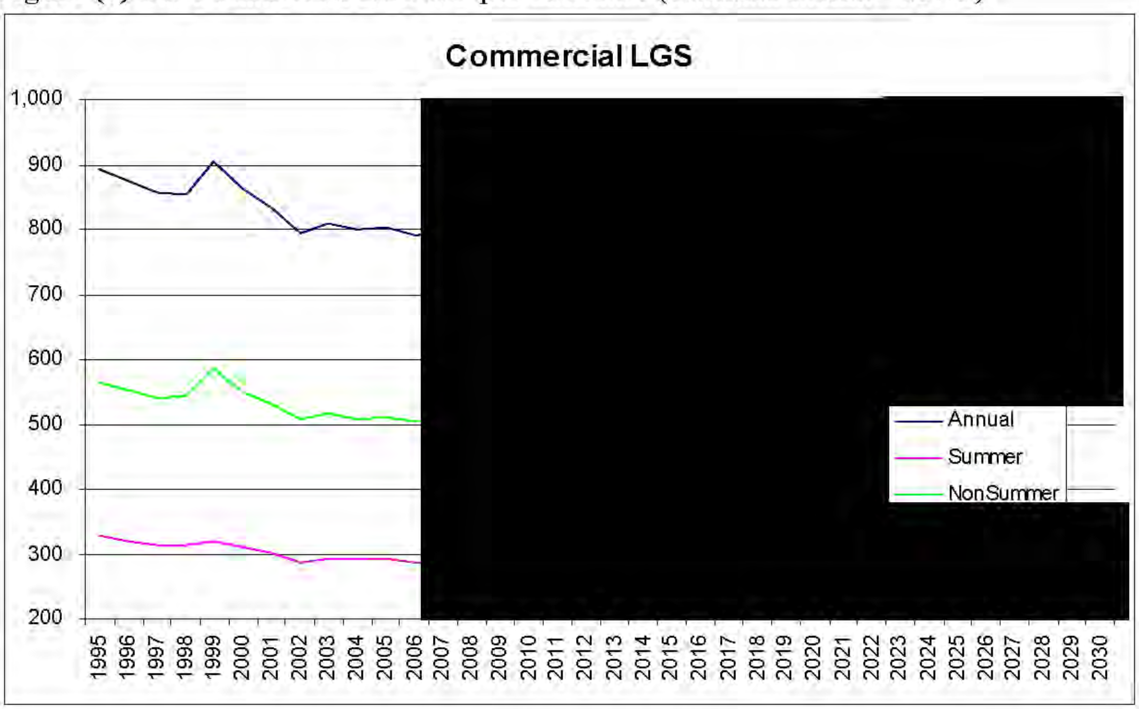


Figure (8)-37: Commercial SPS use-per-customer (Calendar month - MWh)

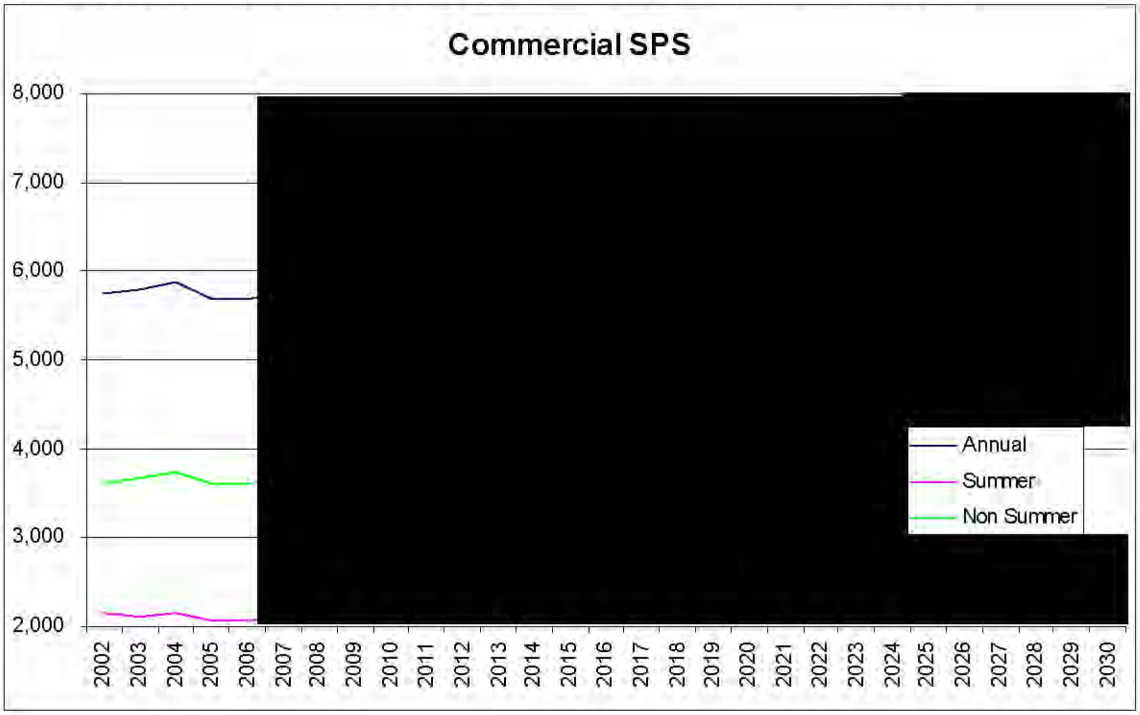


Figure (8)-38: Commercial LPS use-per-customer (Calendar month - MWh)

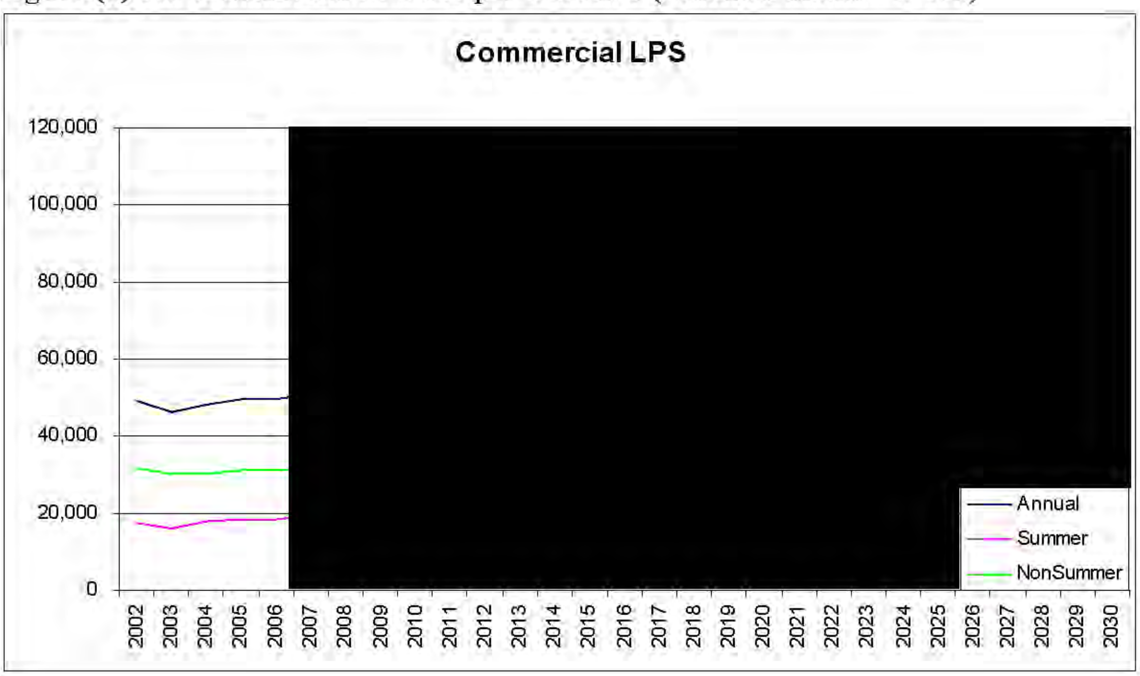


Figure (8)-39: Industrial SGS use-per-customer (Calendar month - MWh)

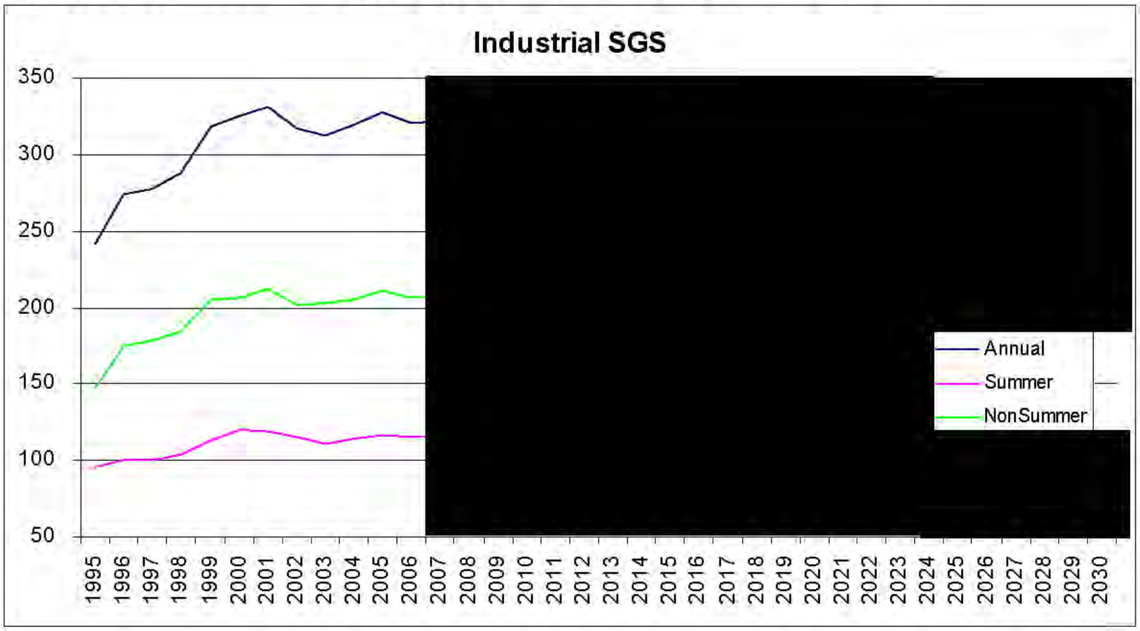


Figure (8)-40: Industrial LGS use-per-customer (Calendar month - MWh)

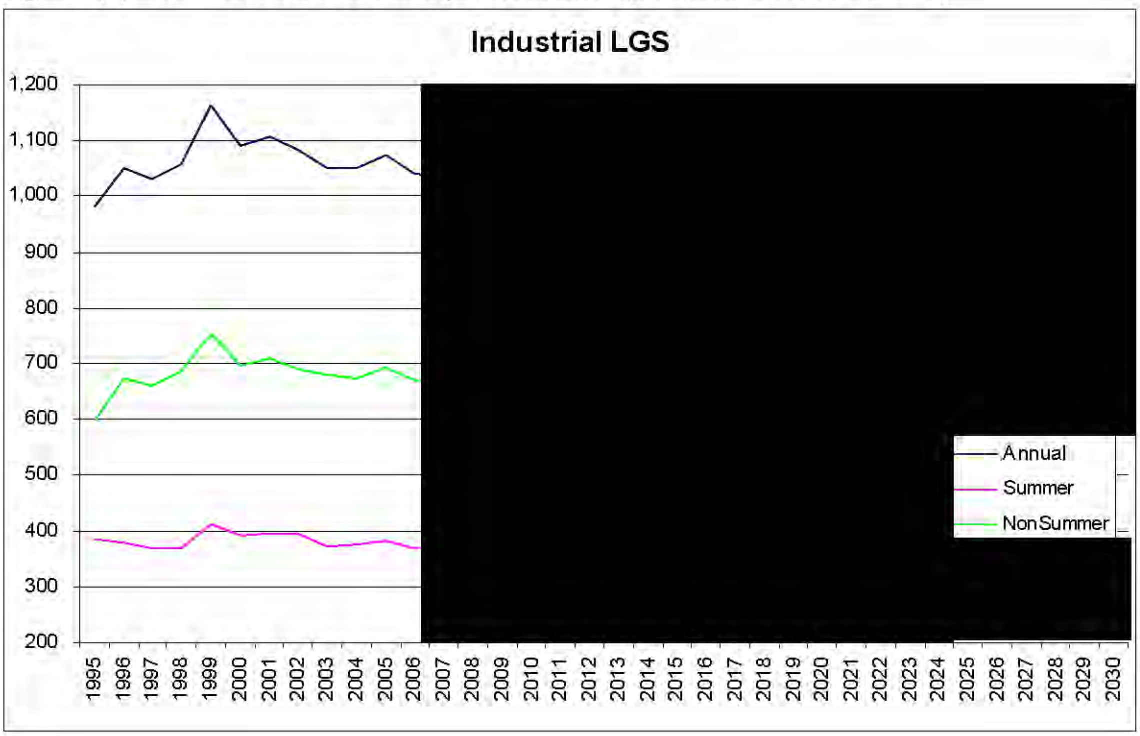


Figure (8)-41: Industrial SPS use-per-customer (Calendar month - MWh)

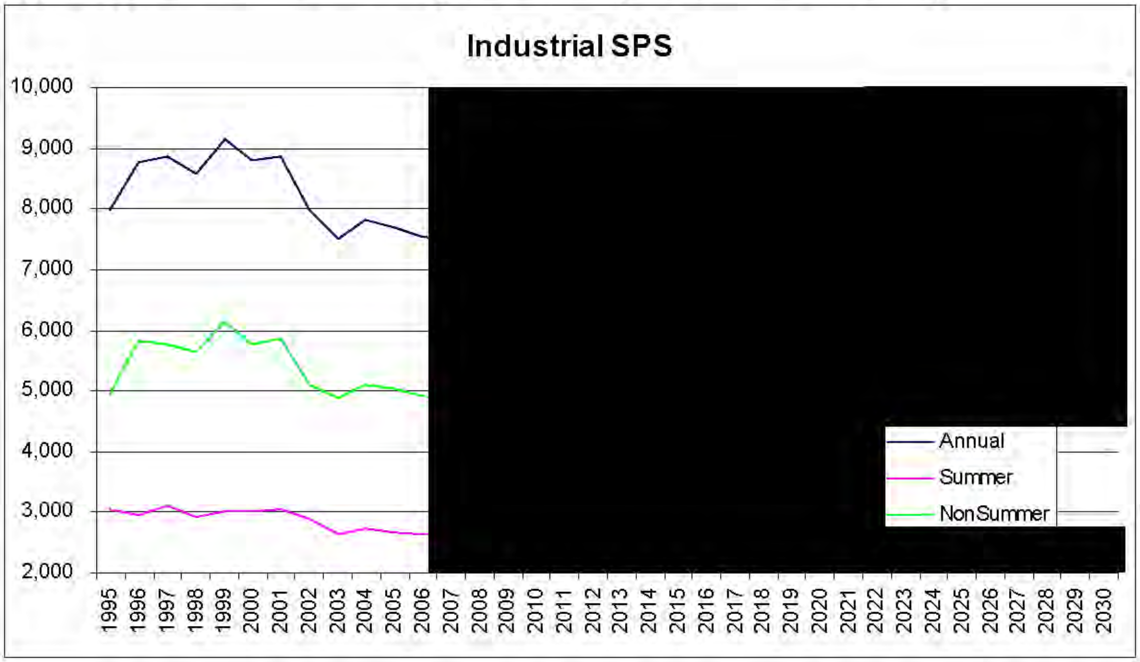


Figure (8)-42: Industrial LPS use-per-customer (Calendar month - MWh)

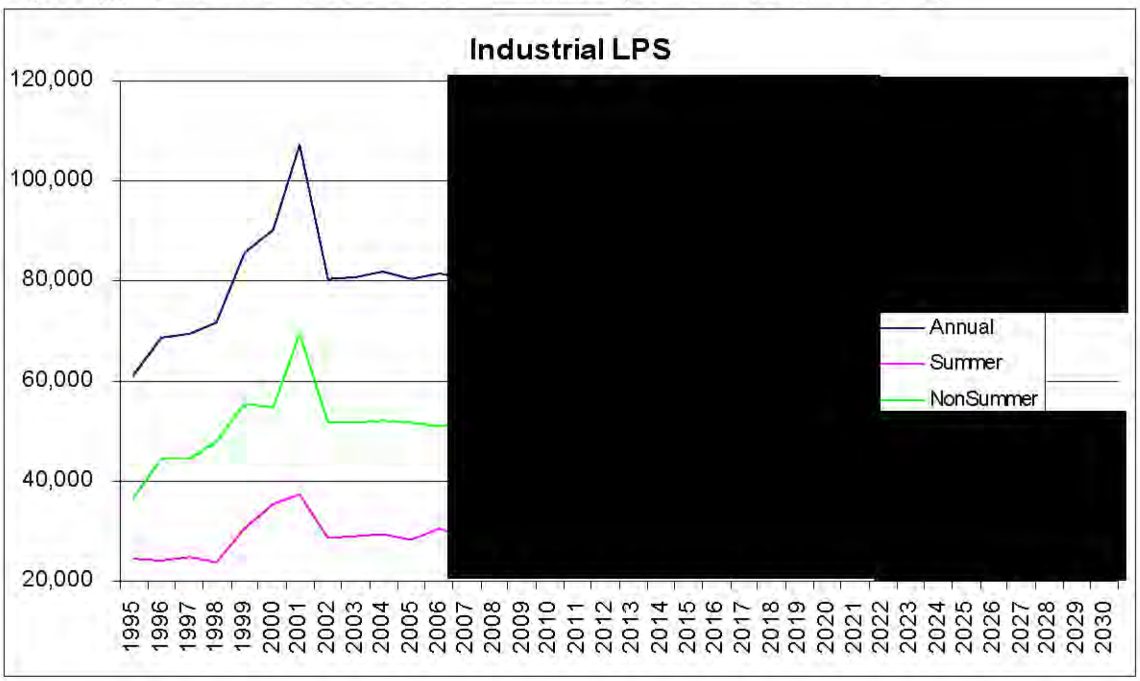


Figure (8)-43: DtD use-per-customer (Calendar month - MWh)

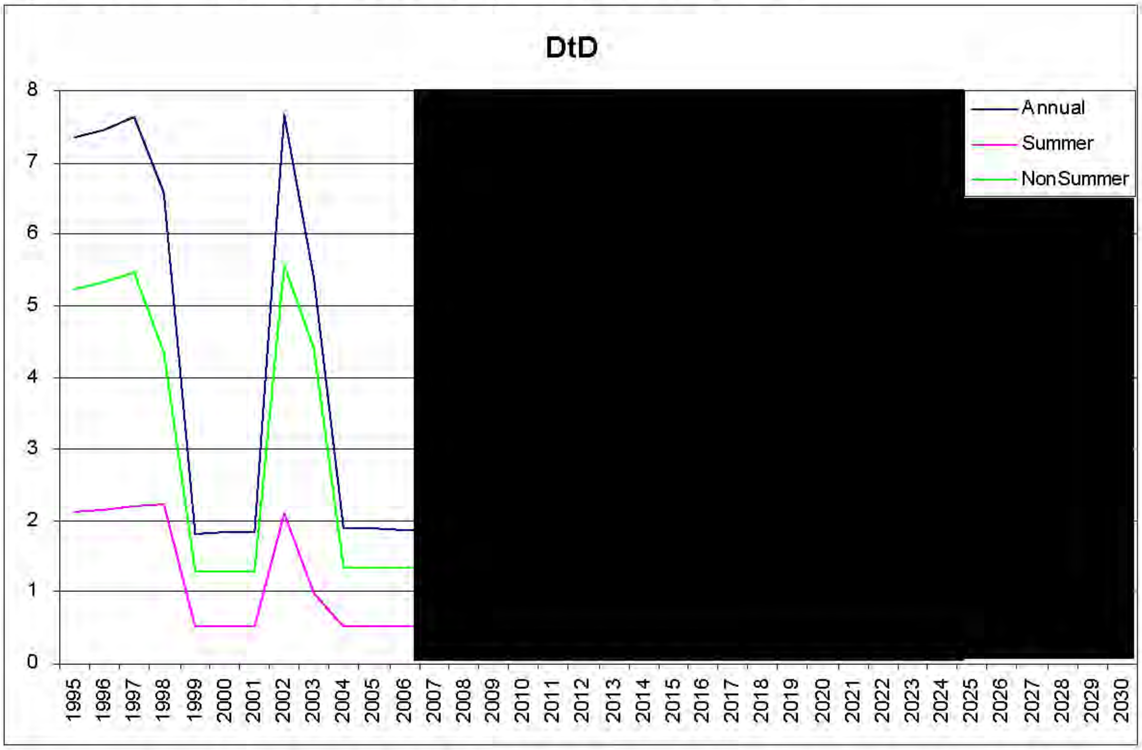


Figure (8)-44: Wholesale use-per-customer (Calendar month - MWh)

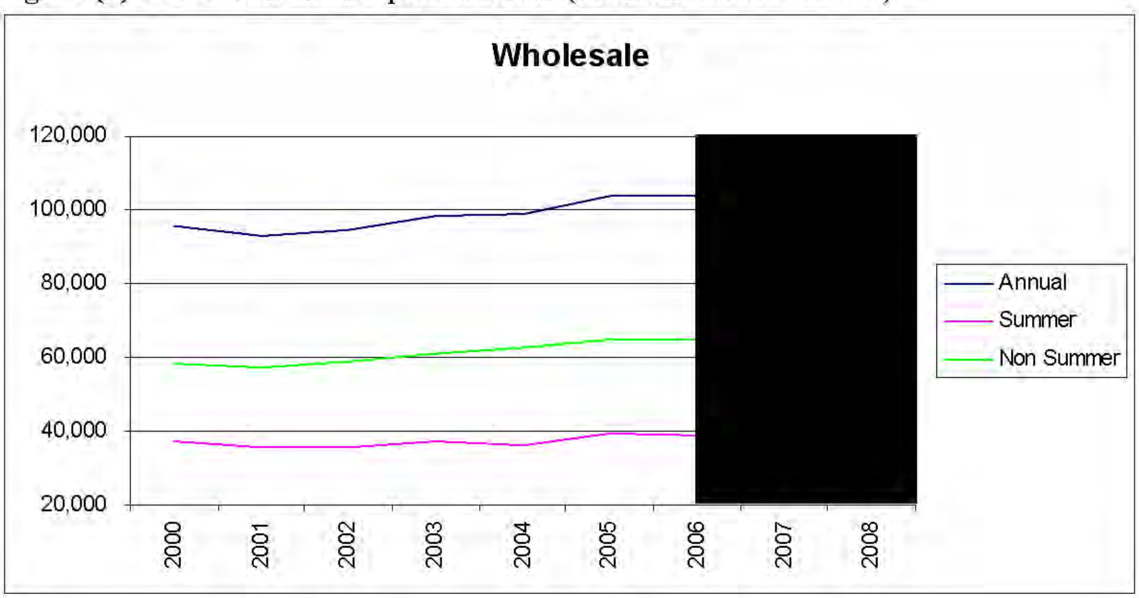


Figure (8)-45: SLPA use-per-customer (Calendar month - MWh)

Figure (8)-46: Residential heating-use (Calendar month - GWh)

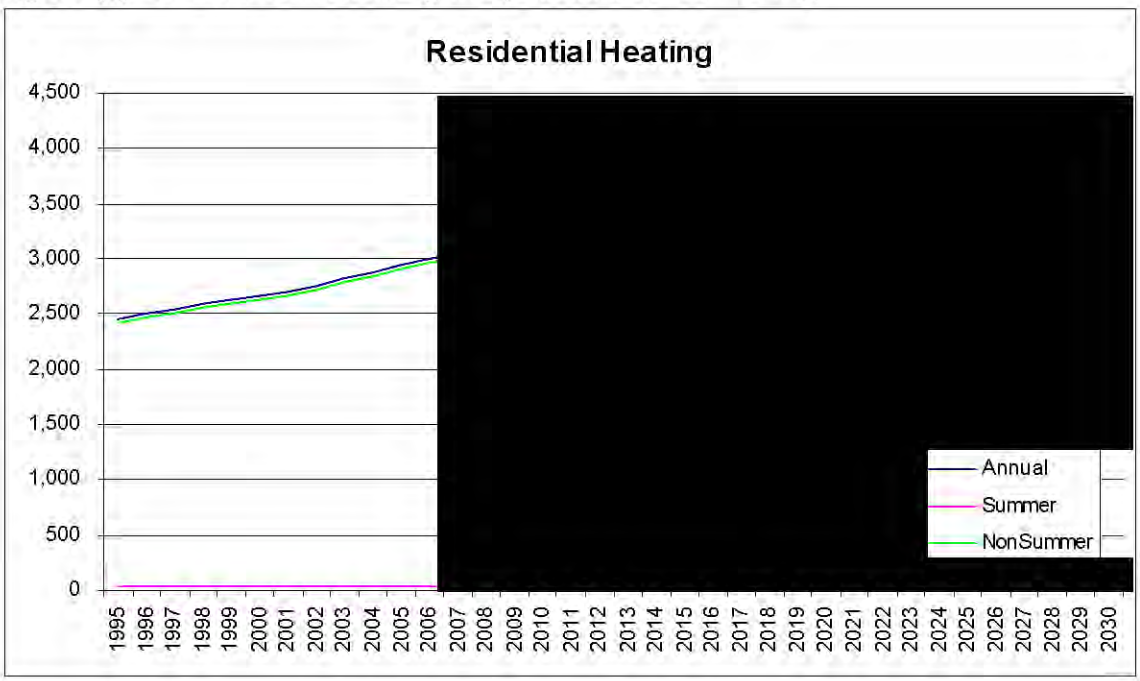


Figure (8)-47: Residential cooling-use (Calendar month - GWh)

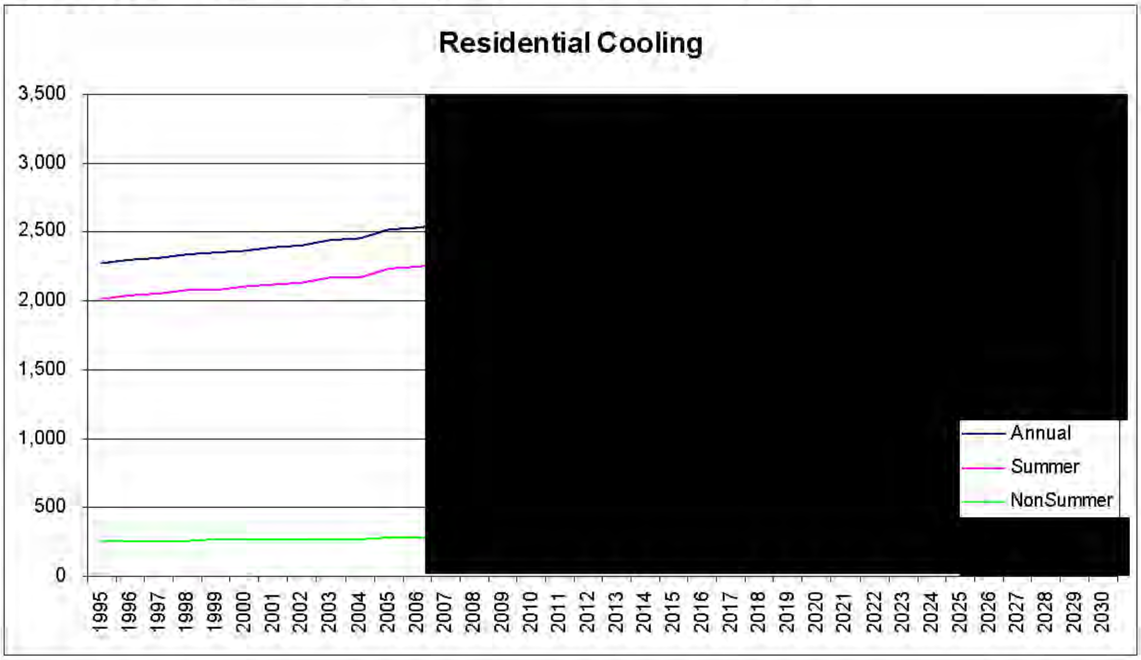


Figure (8)-48: Residential other-use (Calendar month - GWh)

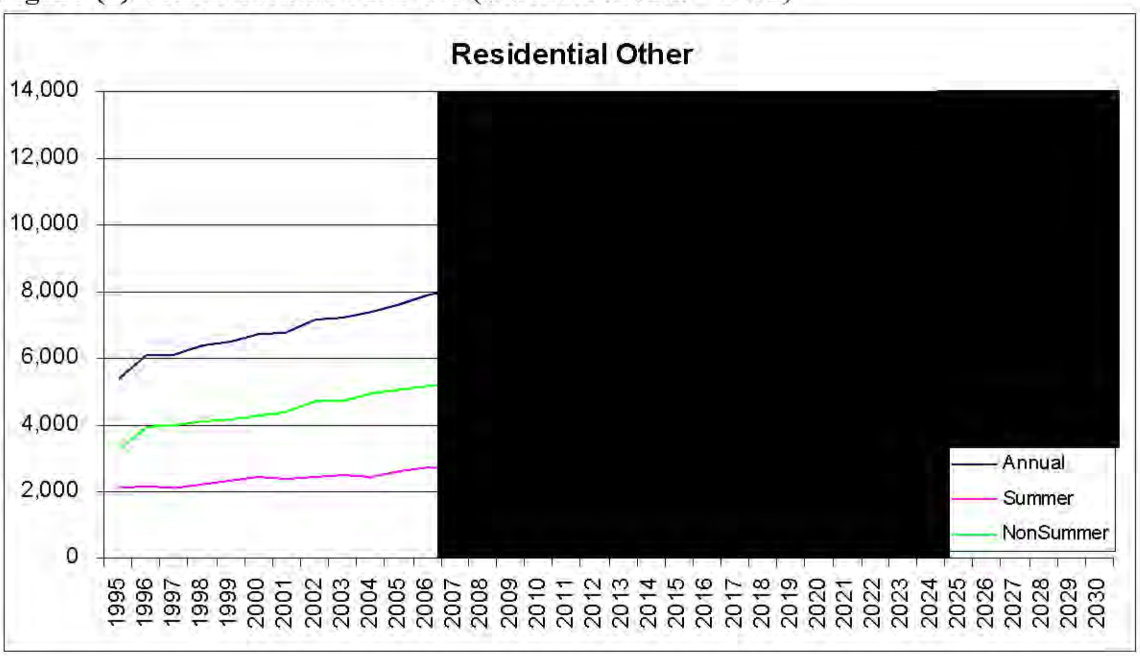


Figure (8)-49: Residential (Calendar month - GWh)

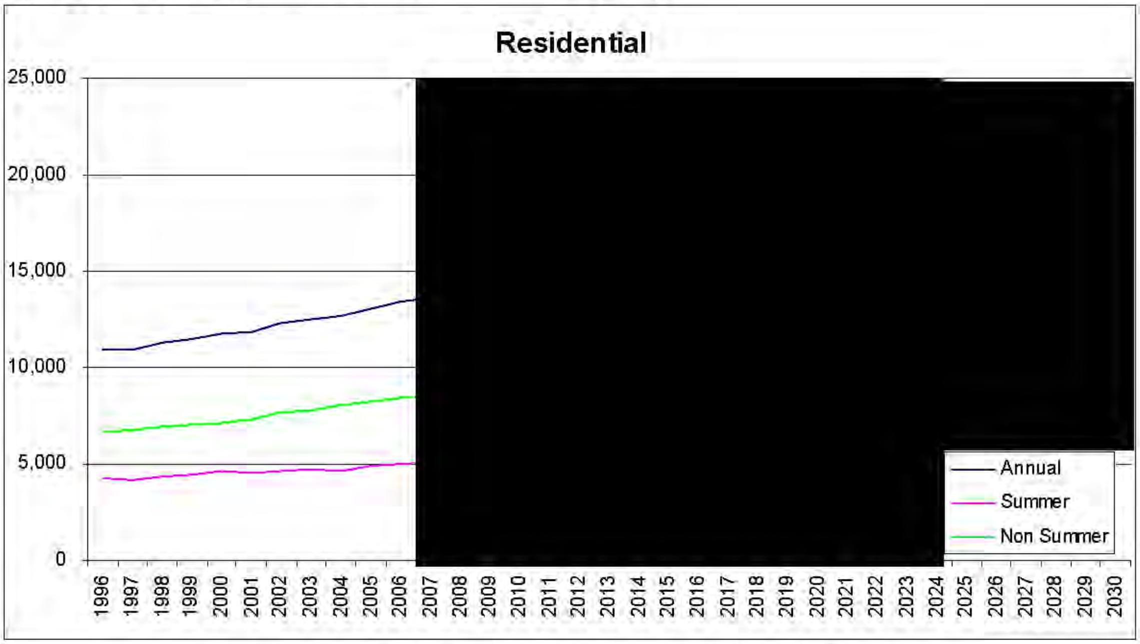


Figure (8)-50: Commercial SGS heating-use (Calendar month - GWh)

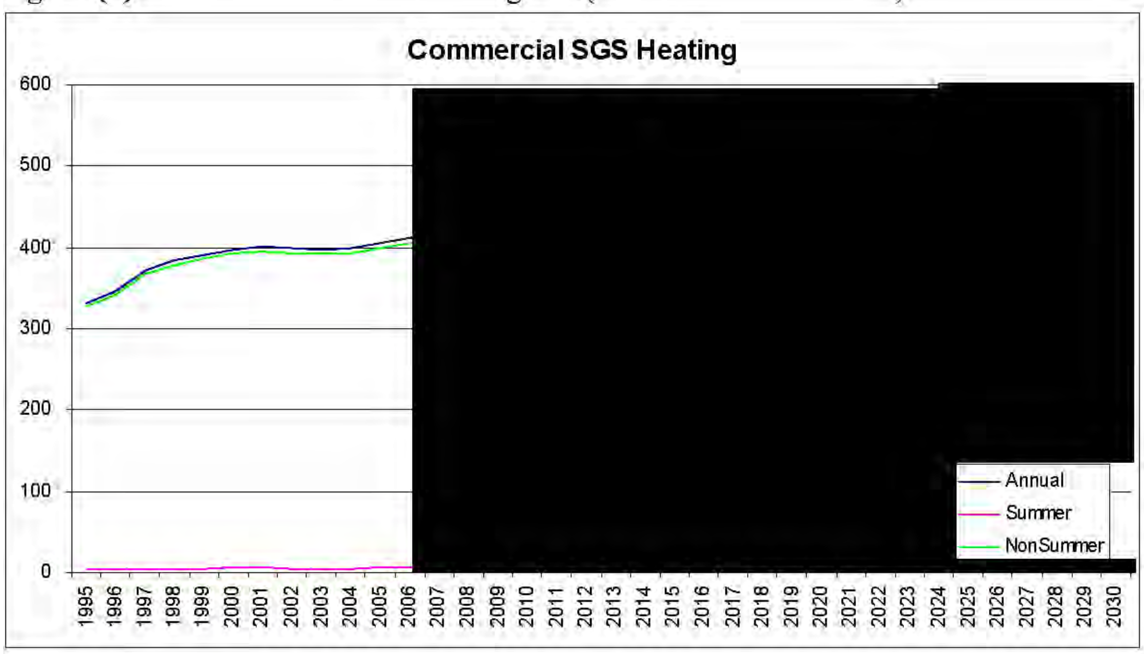


Figure (8)-51: Commercial SGS cooling-use (Calendar month - GWh)

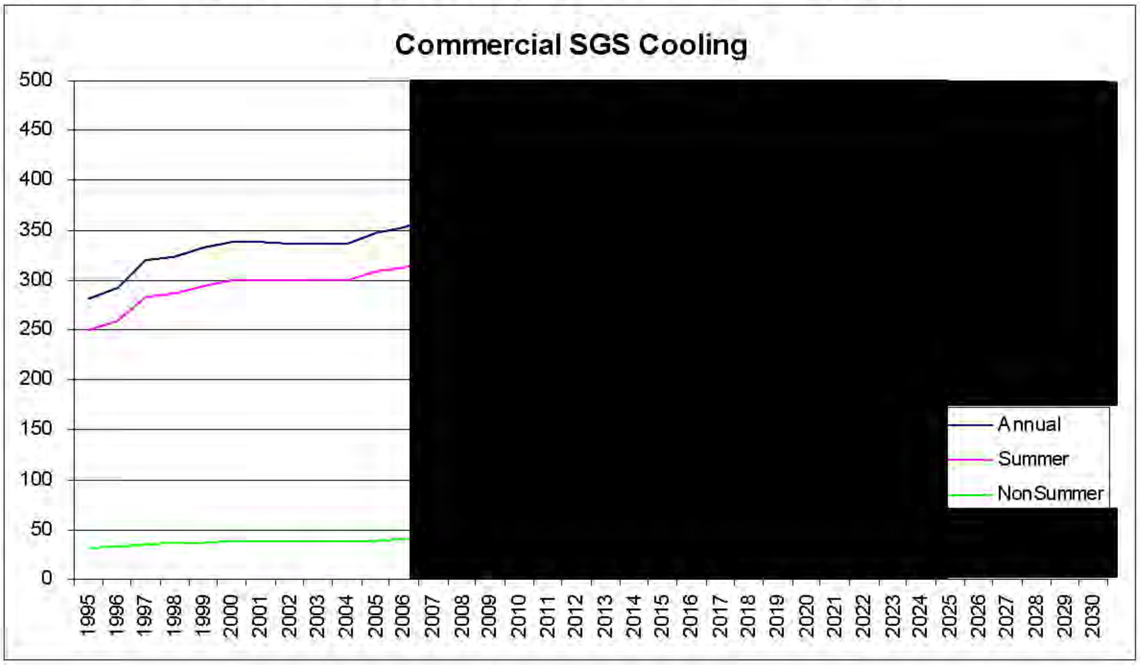


Figure (8)-52: Commercial SGS other-use (Calendar month - GWh)

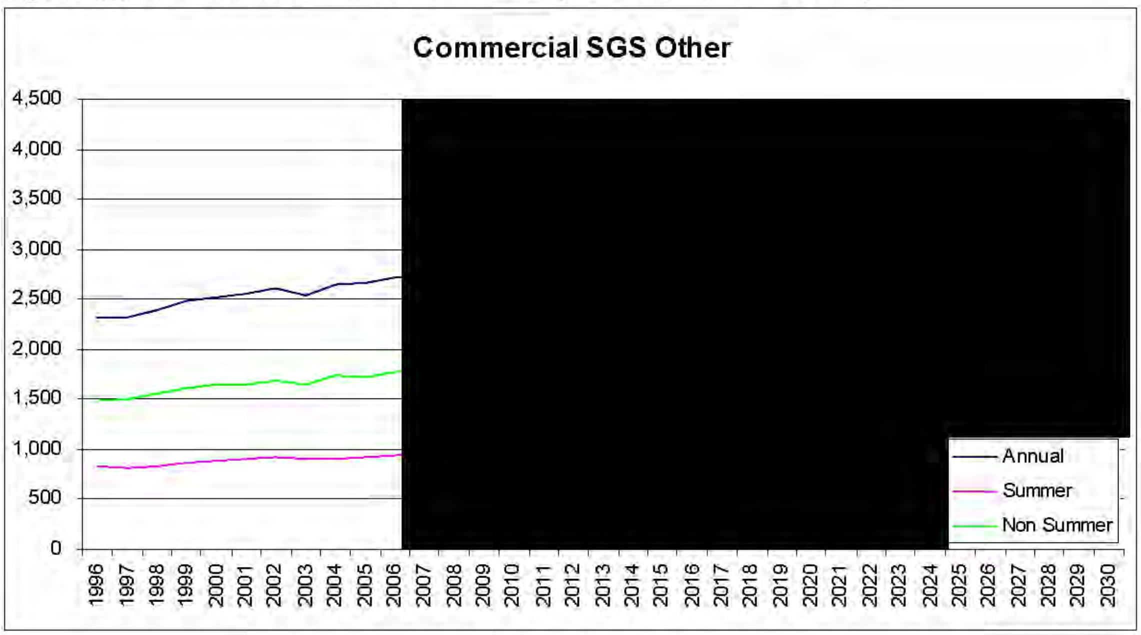


Figure (8)-53: Commercial SGS (Calendar month - GWh)

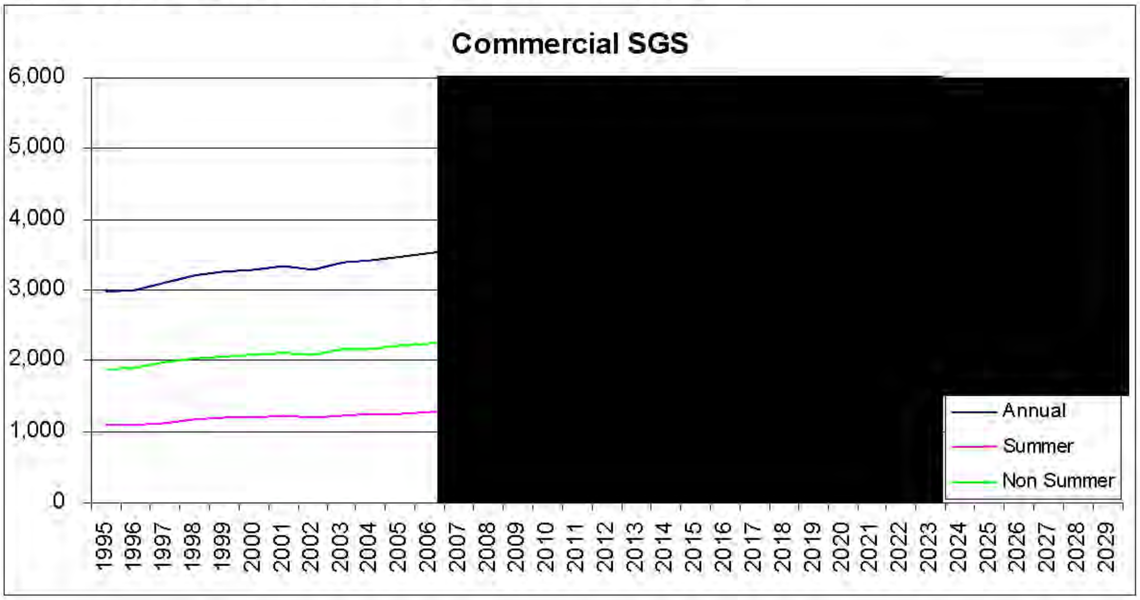


Figure (8)-54: Commercial LGS heating-use (Calendar month - GWh)

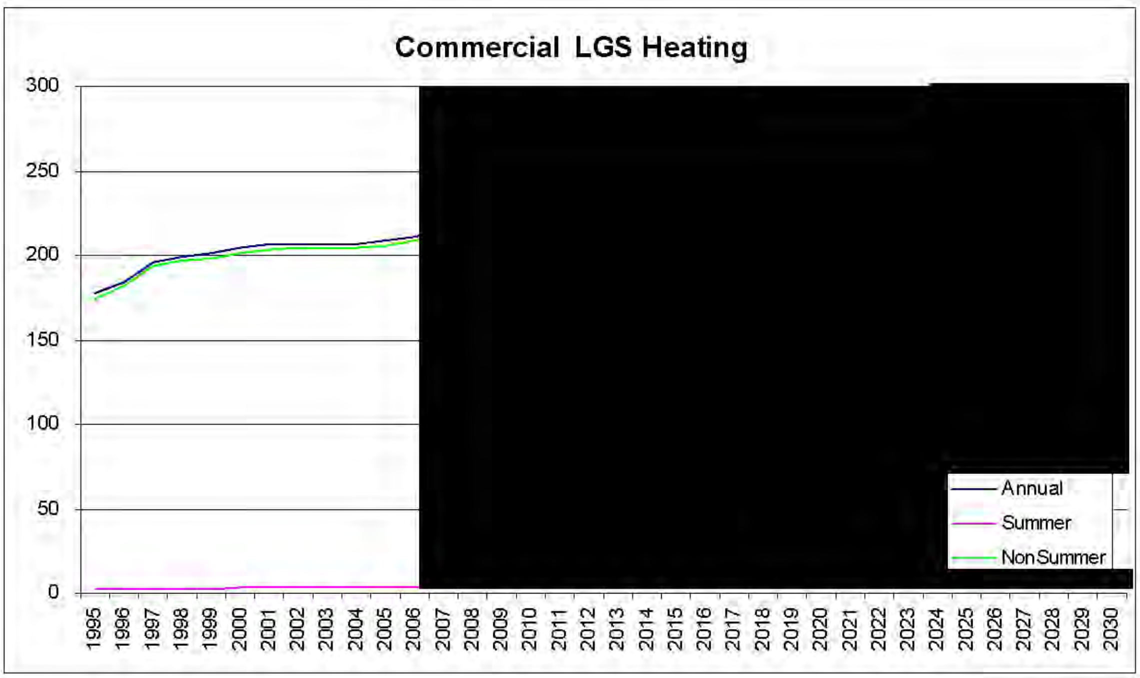


Figure (8)-55: Commercial LGS cooling-use (Calendar month - GWh)

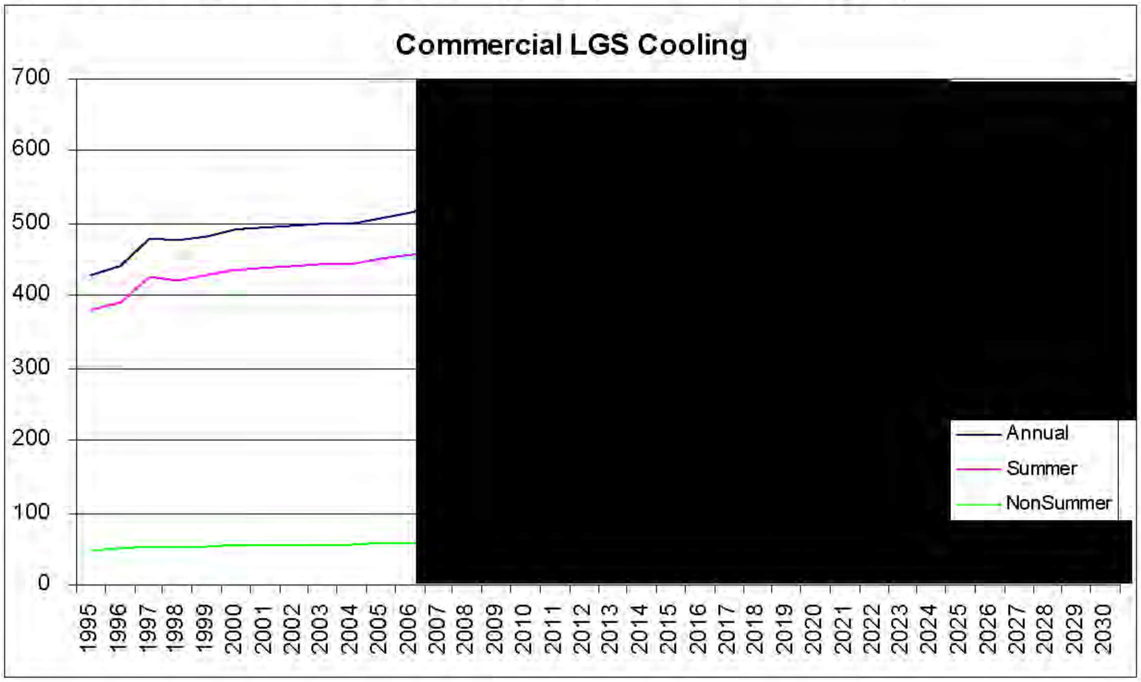


Figure (8)-56: Commercial LGS other-use (Calendar month - GWh)

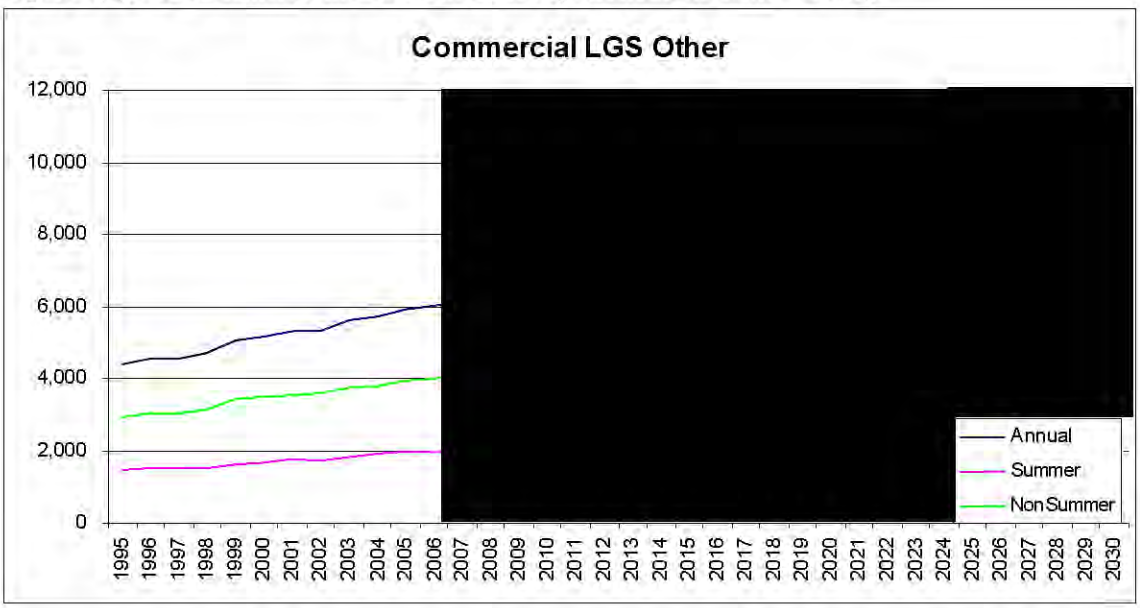


Figure (8)-57: Commercial LGS (Calendar month - GWh)

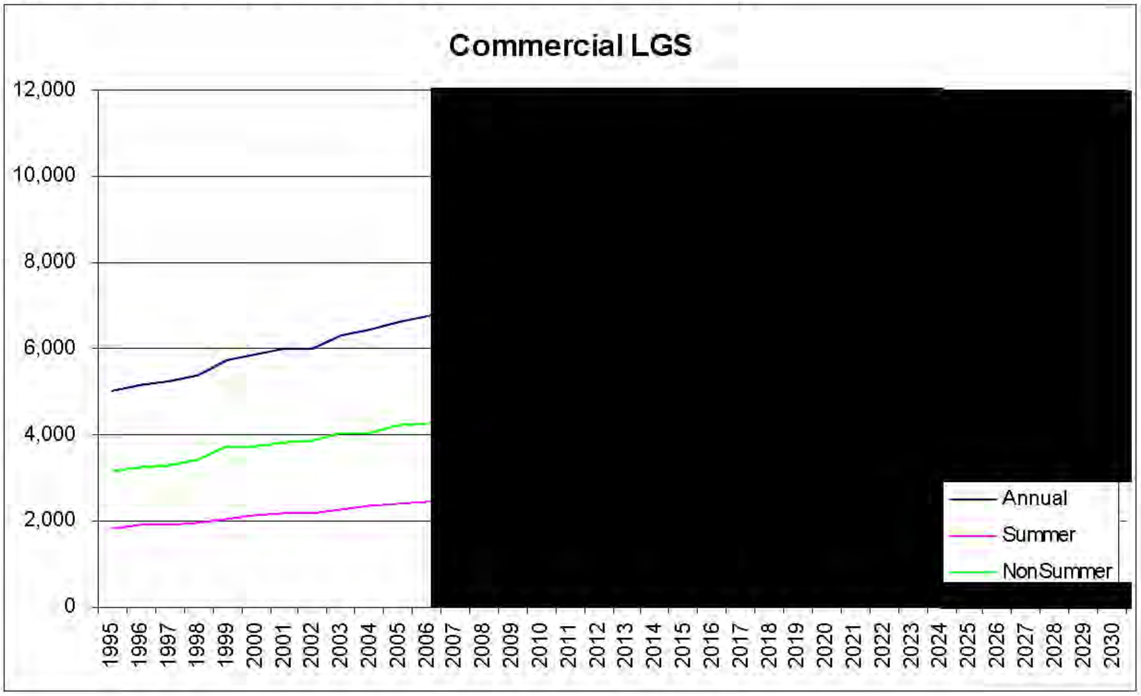


Figure (8)-58: Commercial SPS (Calendar month - GWh)

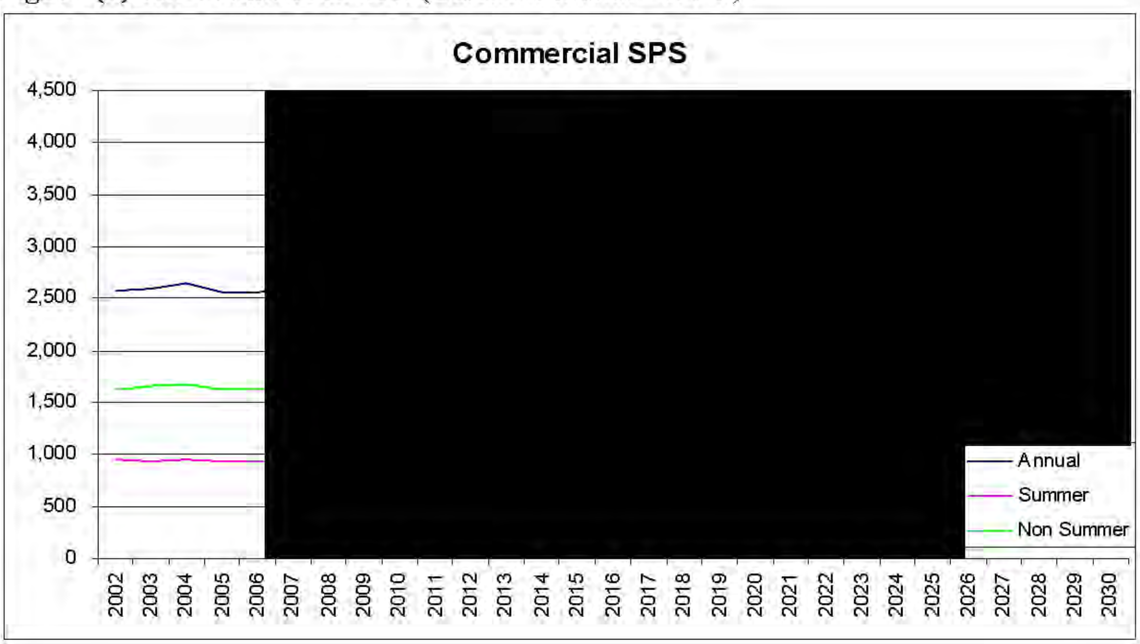


Figure (8)-59: Commercial LPS (Calendar month - GWh)

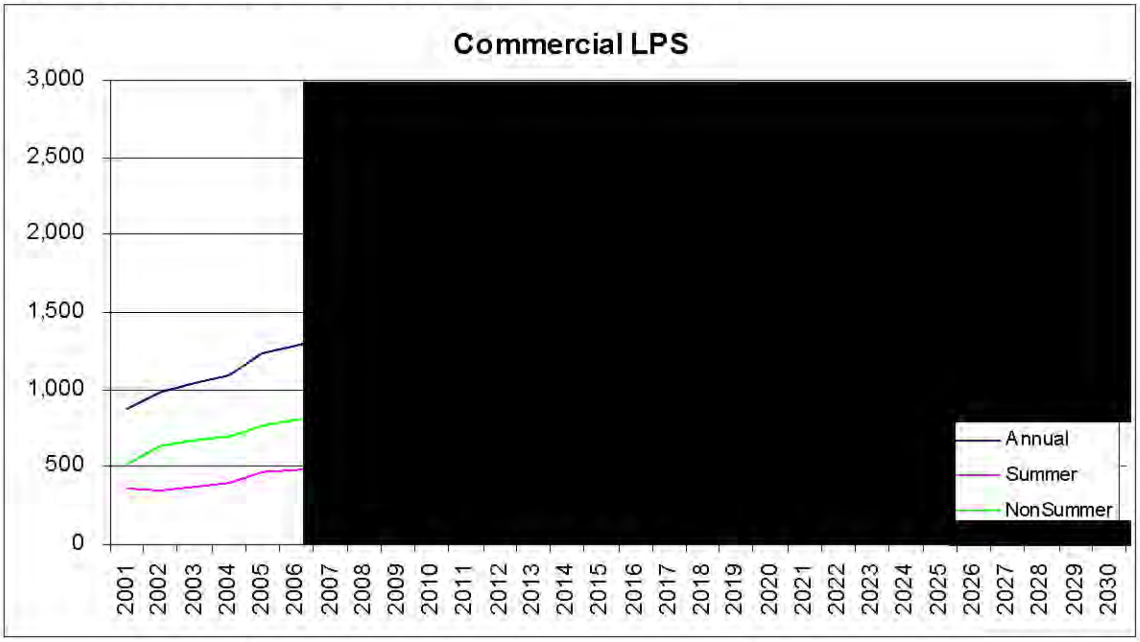


Figure (8)-60: Industrial SGS (Calendar month - GWh)

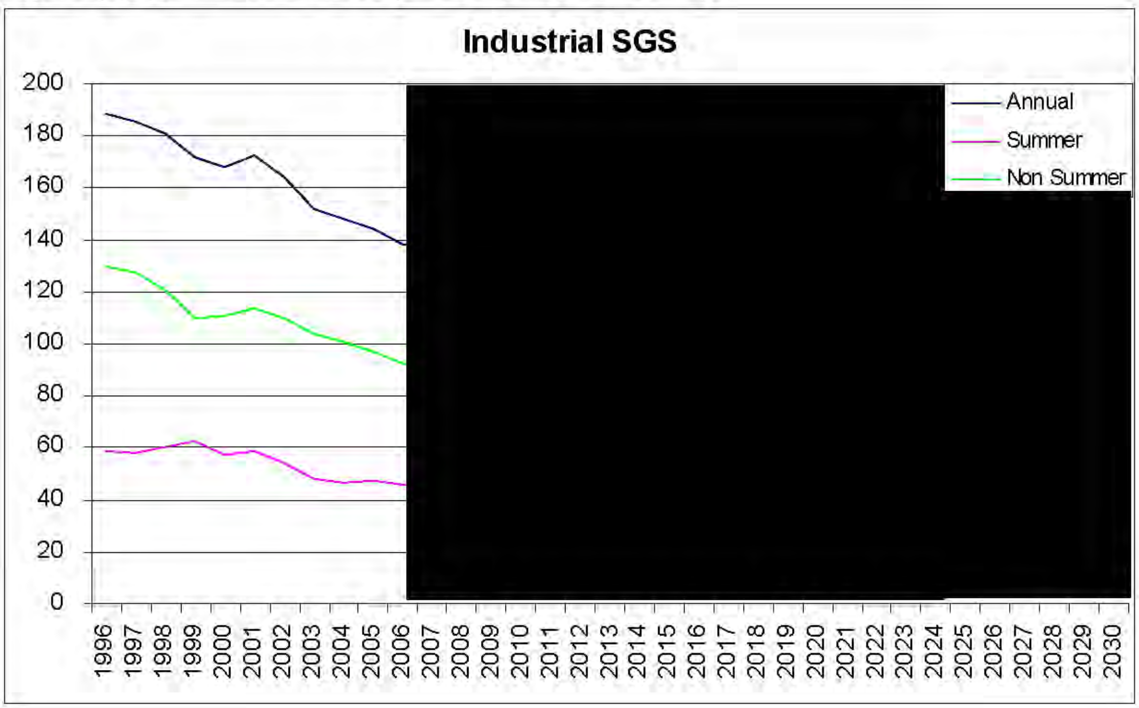


Figure (8)-61: Industrial LGS (Calendar month - GWh)

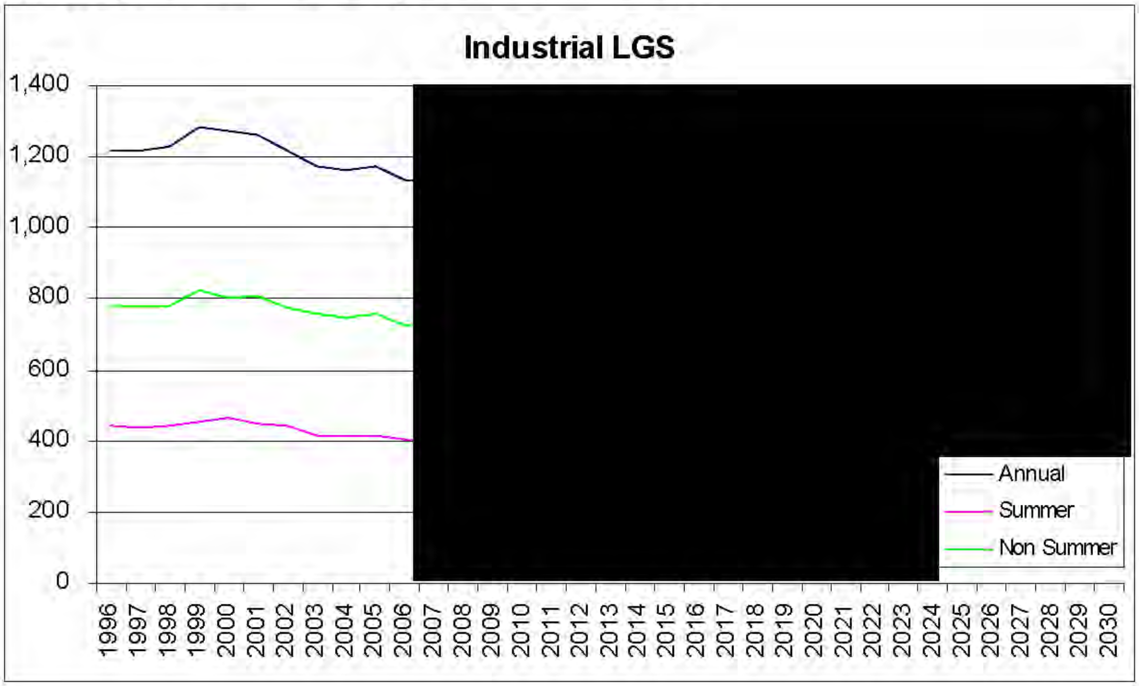


Figure (8)-62: Industrial LGS (Calendar month - GWh)

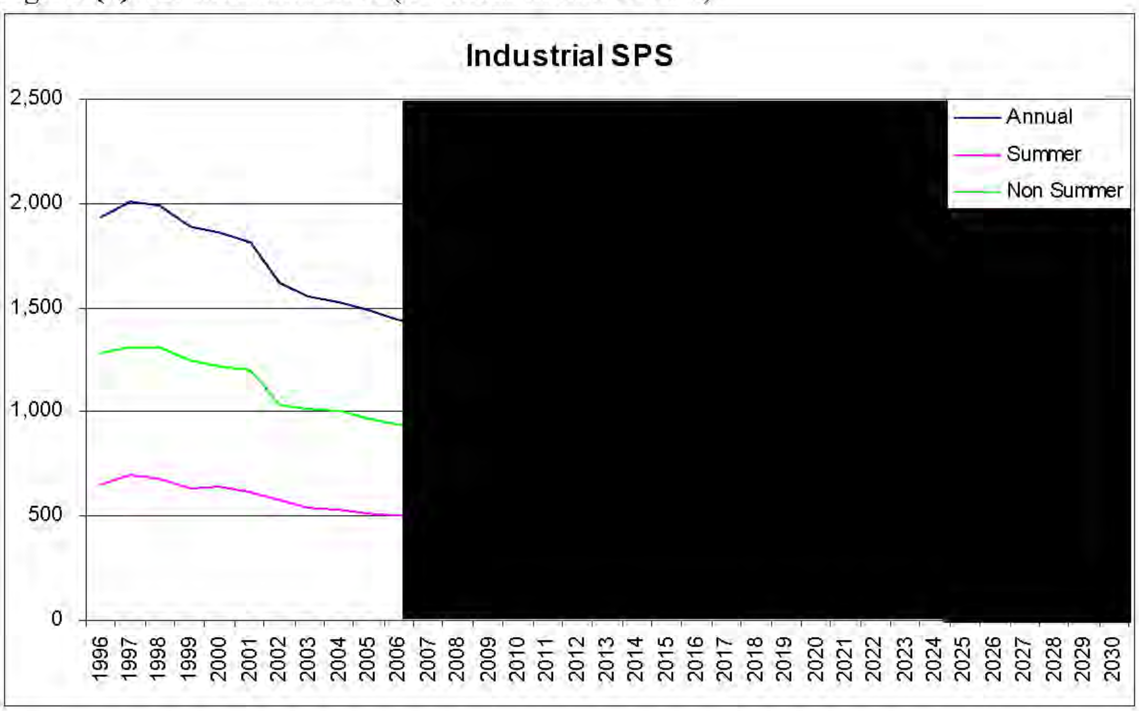


Figure (8)-63: Industrial LPS (Calendar month - GWh)

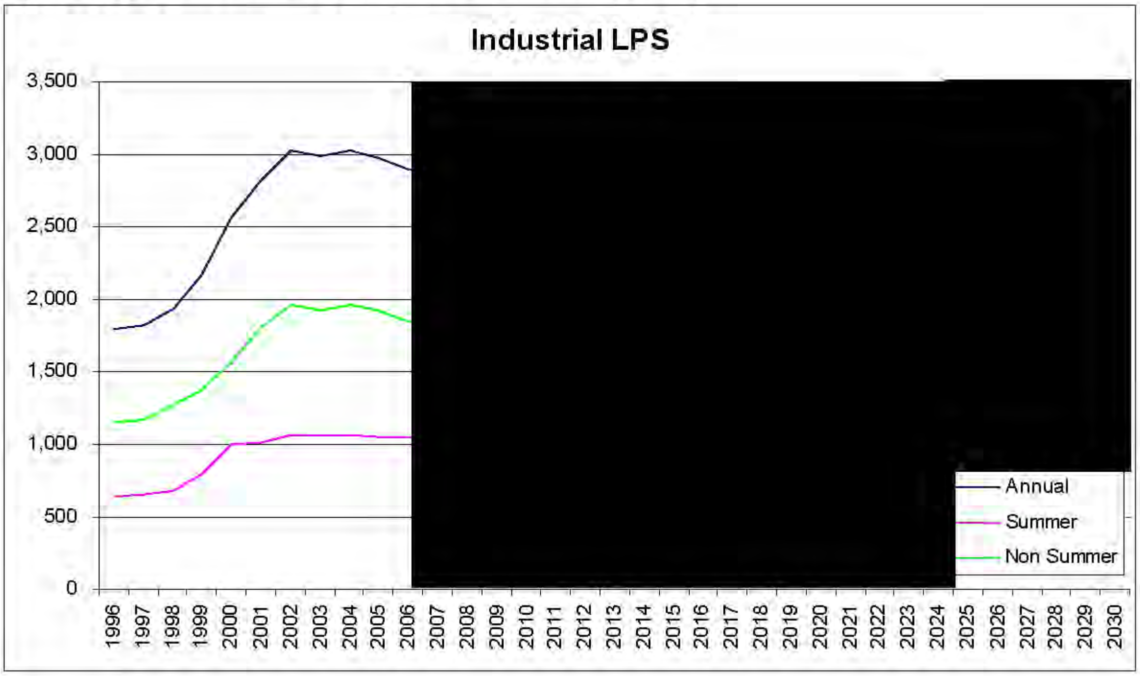


Figure (8)-64: Noranda (Calendar month - GWh)

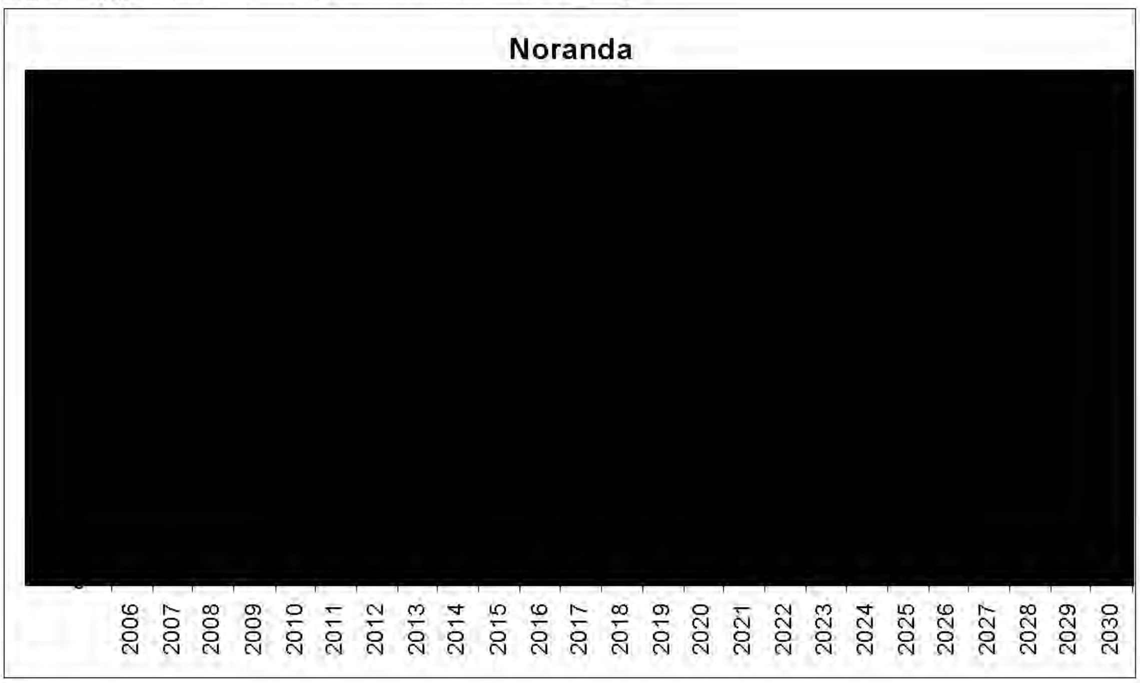


Figure (8)-65: DtD (Calendar month - GWh)

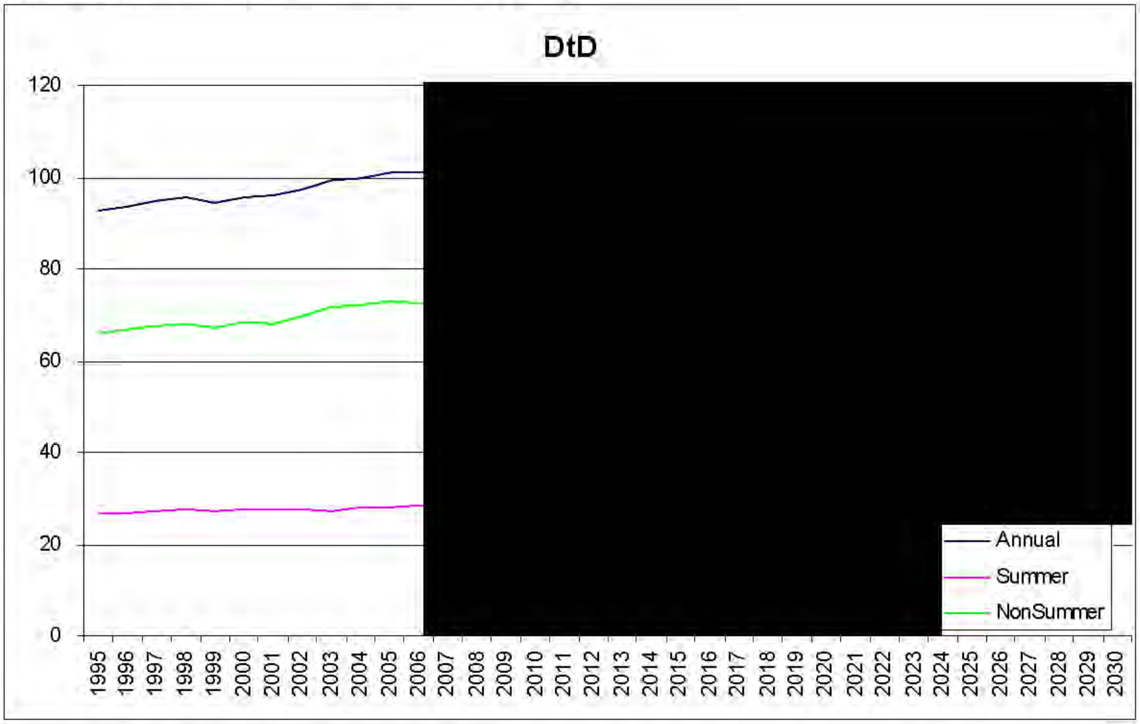


Figure (8)-66: Wholesale (Calendar month - GWh)

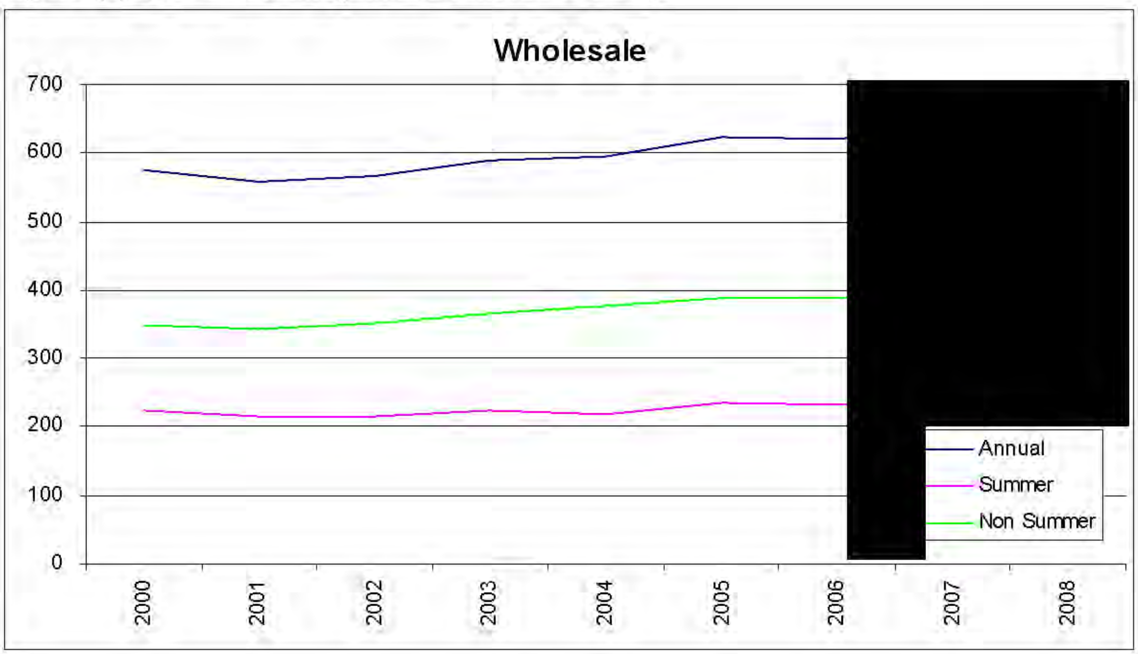


Figure (8)-67: SLPA (Calendar month - GWh)

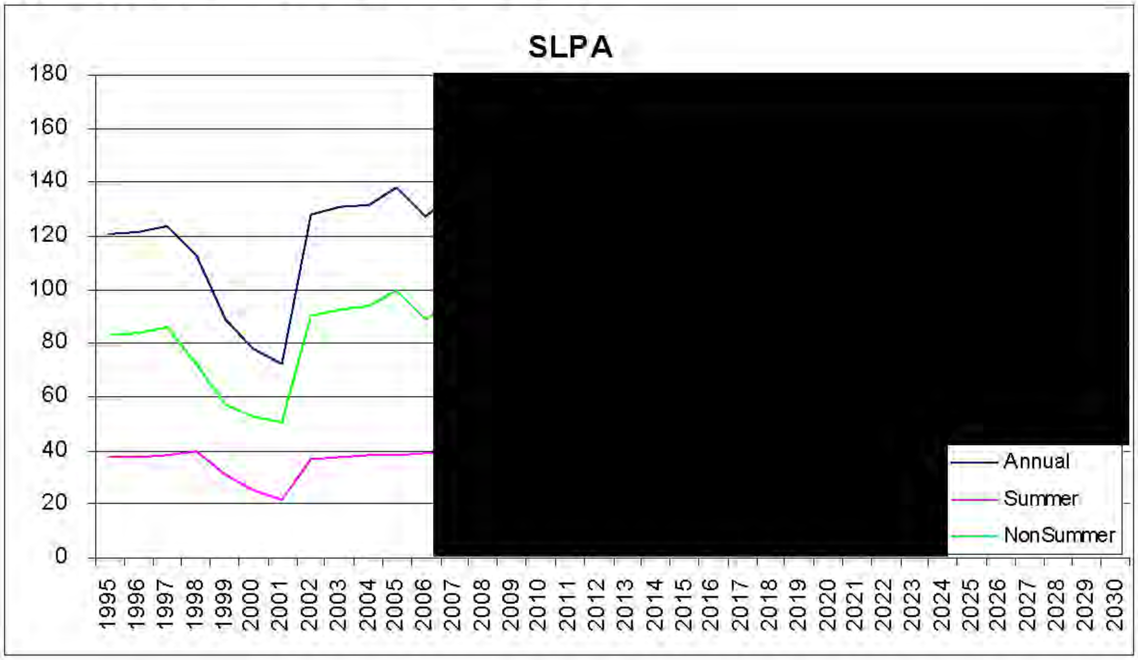
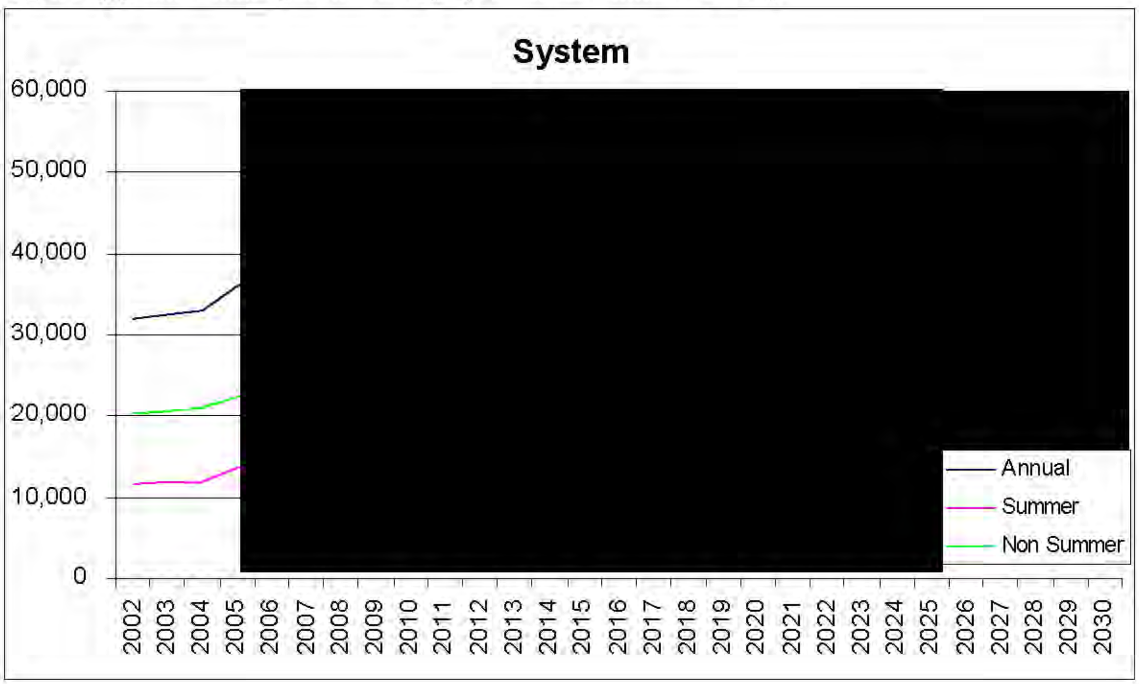


Figure (8)-68: Total system energy (Calendar month - GWh)



4 CSR 240-22.030 (8) (B)

(B) For each major class specified in subsection (1)(A), the utility shall provide plots of class demand per unit and class total demand at time of summer and winter system peak. The plots shall cover the historical data base period and the forecast period of at least twenty (20) years.

1. The plots for the historical period shall include both actual and weather-normalized class demands per unit and total demands at the time of summer and winter system peak demands.

2. The plots for the forecast period shall show each end-use component of major class coincident demands per unit and total class coincident demands for the base-case forecast.

Figure (8)-69: Actual coincident class peak-per-customer (MW)

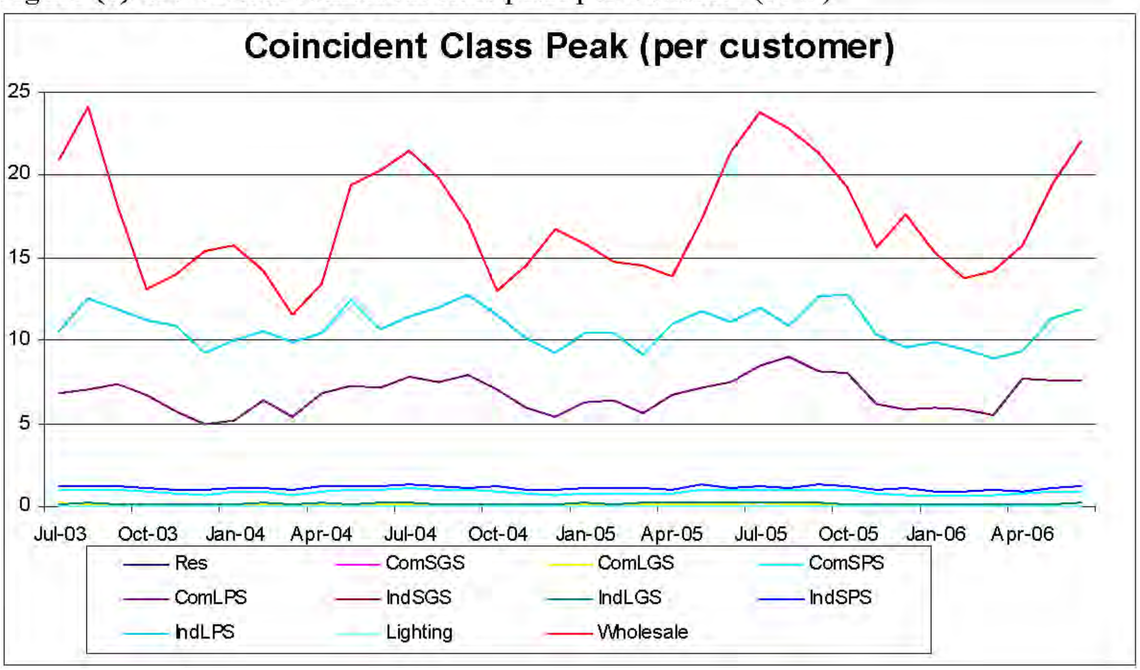


Figure (8)-70: Weather-normalized coincident class peak-per-customer (MW)

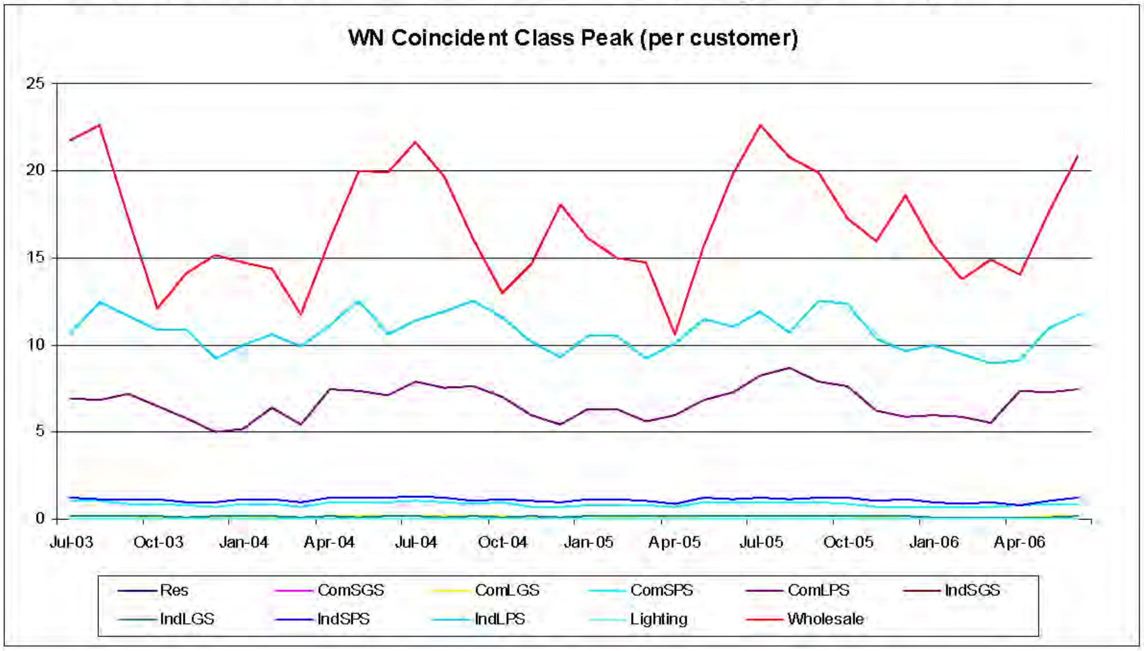


Figure (8)-71: Residential heating-use coincident peak-per-customer (MW)

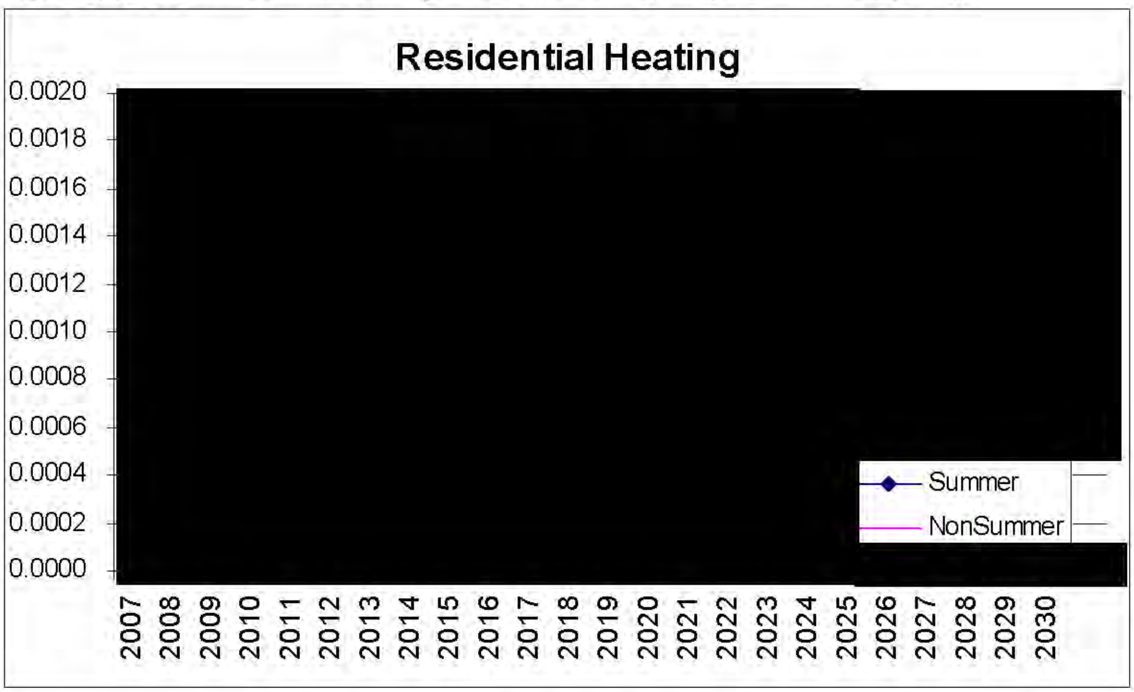


Figure (8)-72: Residential cooling-use coincident peak-per-customer (MW)

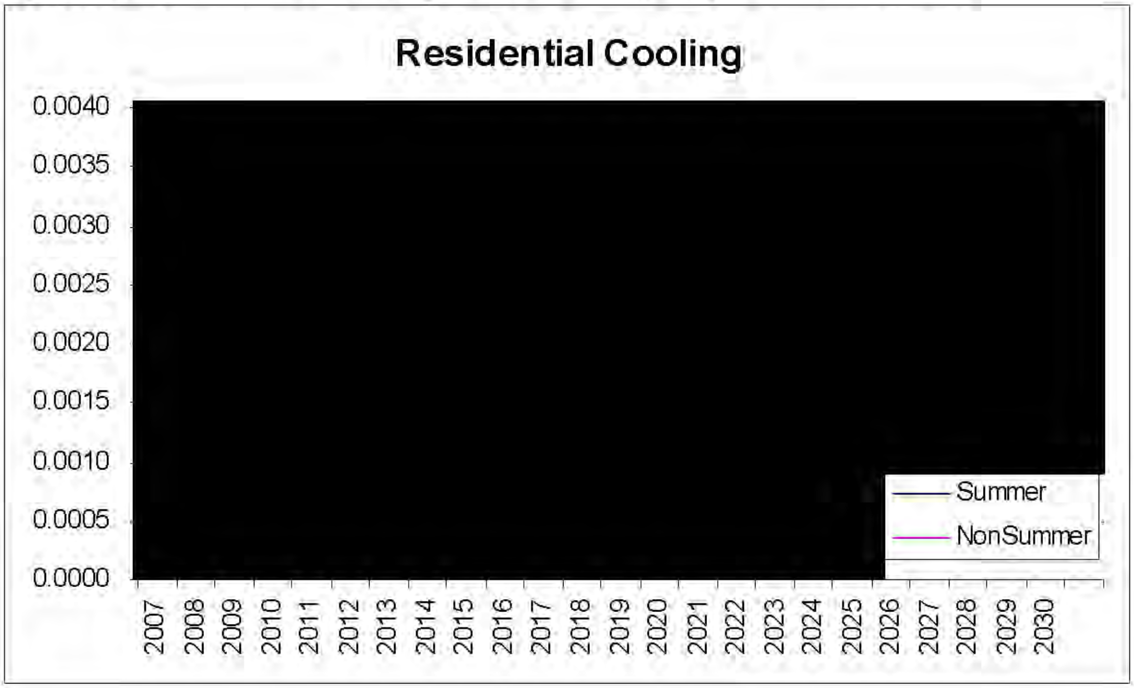


Figure (8)-73: Residential other-use coincident peak-per-customer (MW)

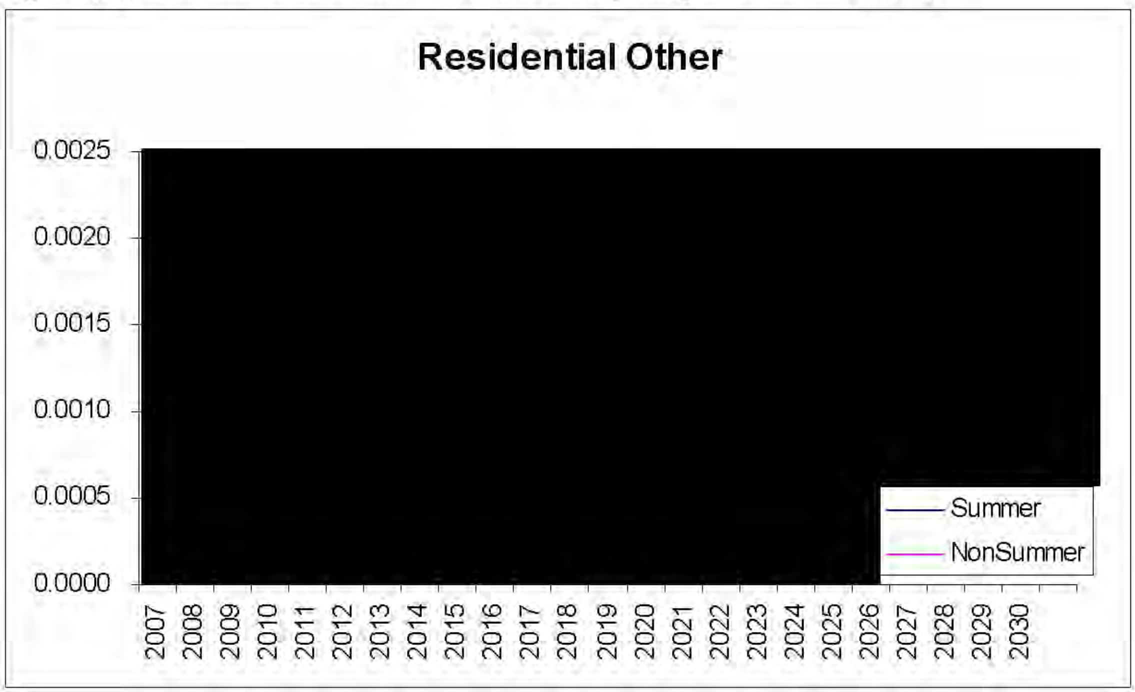


Figure (8)-74: Residential coincident peak-per-customer (MW)

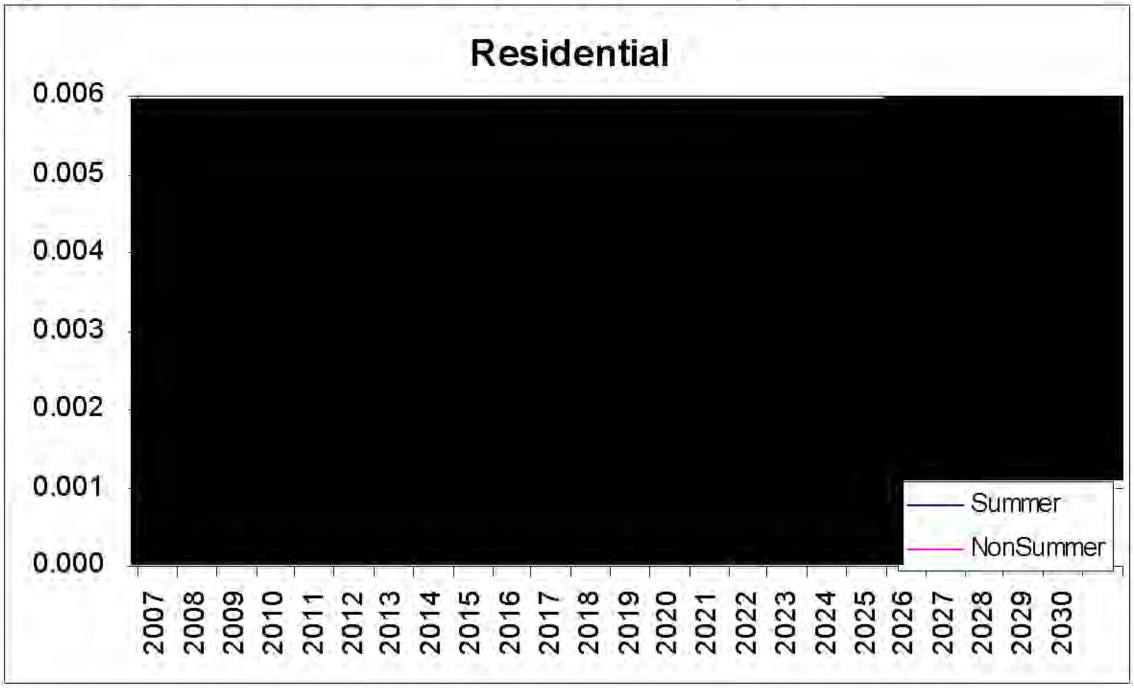


Figure (8)-75: Commercial SGS coincident peak-per-customer (MW)

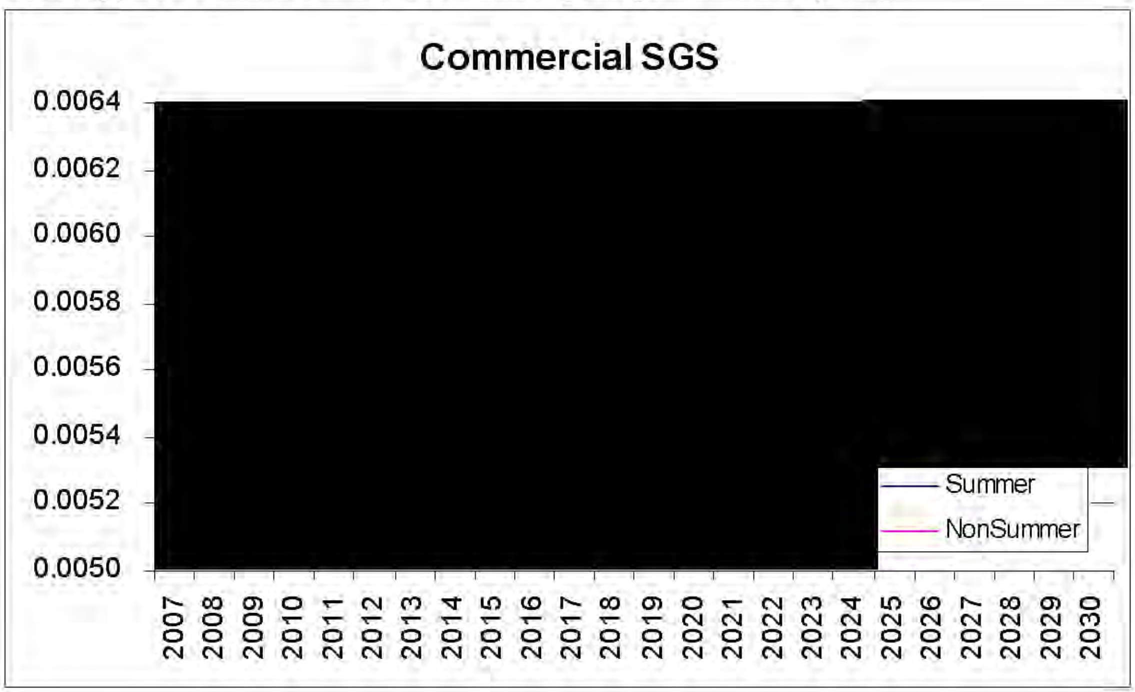


Figure (8)-76: Commercial LGS coincident peak-per-customer (MW)

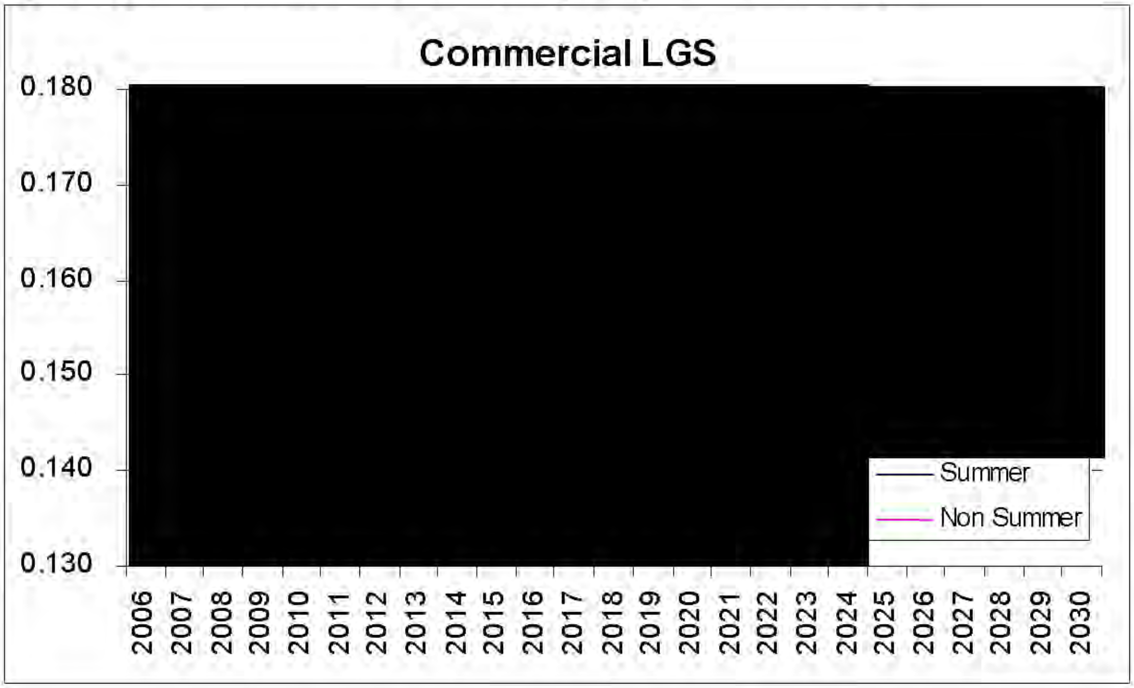


Figure (8)-77: Commercial SPS coincident peak-per-customer (MW)

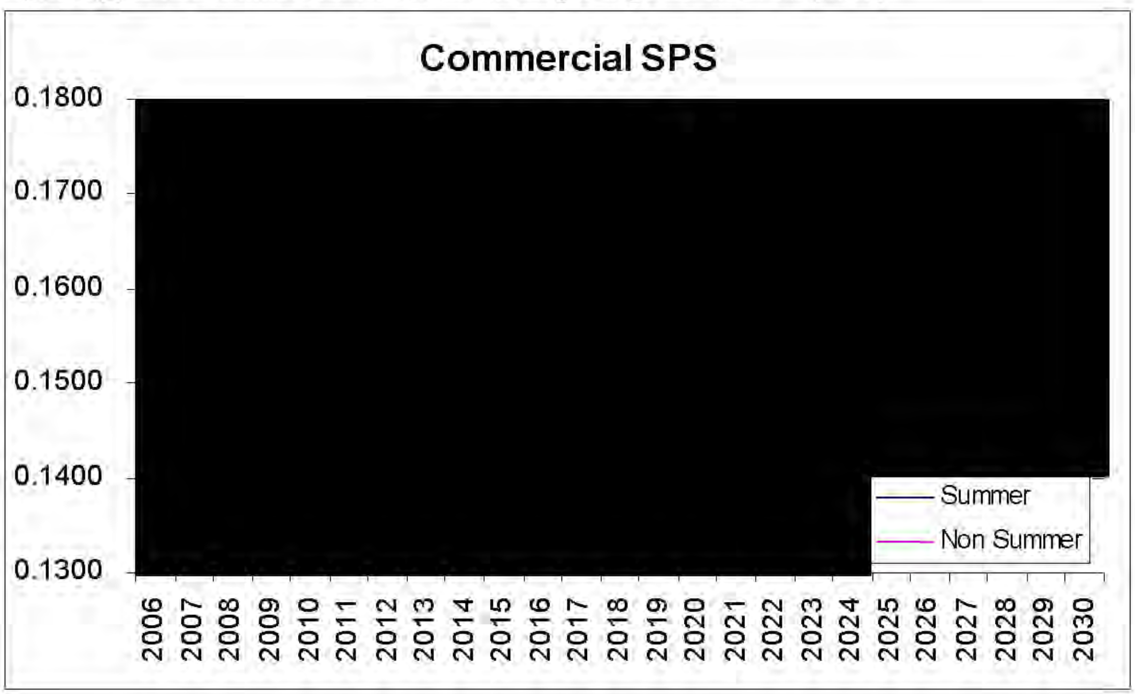


Figure (8)-78: Commercial LPS coincident peak-per-customer (MW)

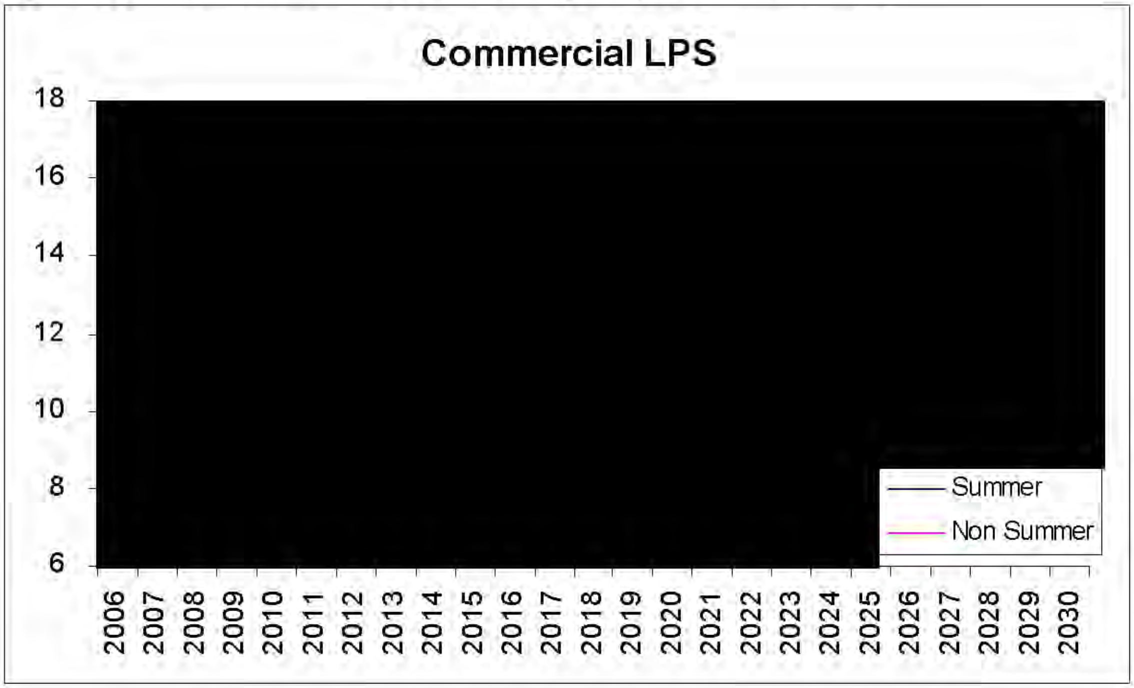


Figure (8)-79: Industrial SGS coincident peak-per-customer (MW)

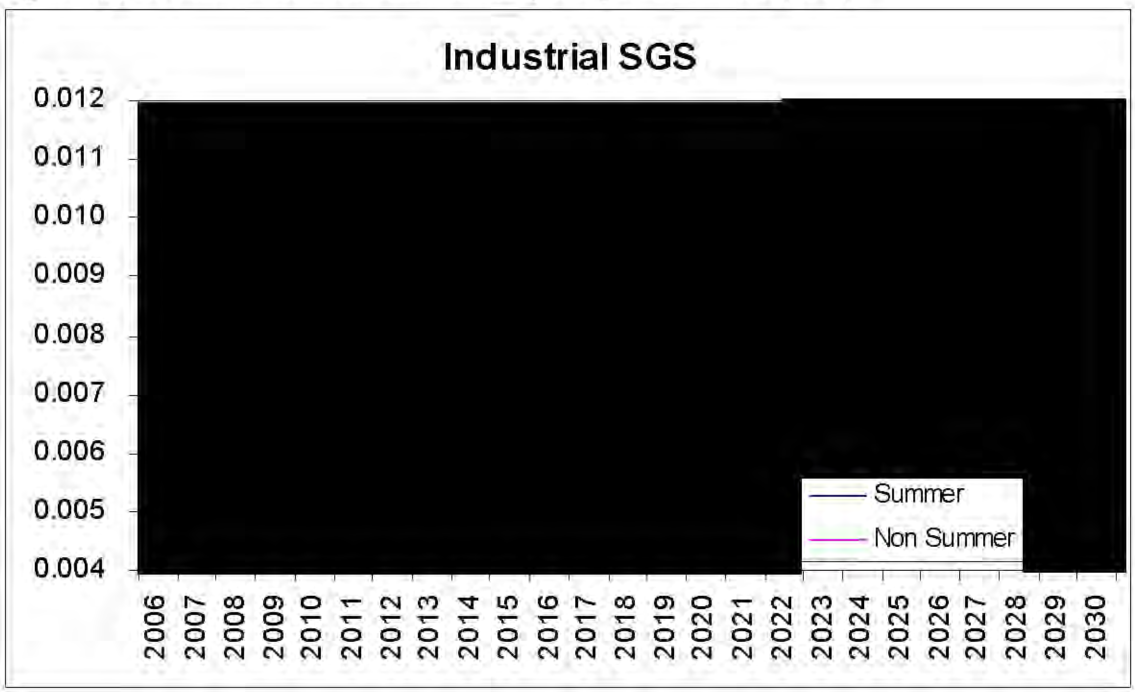


Figure (8)-80: Industrial LGS coincident peak-per-customer (MW)

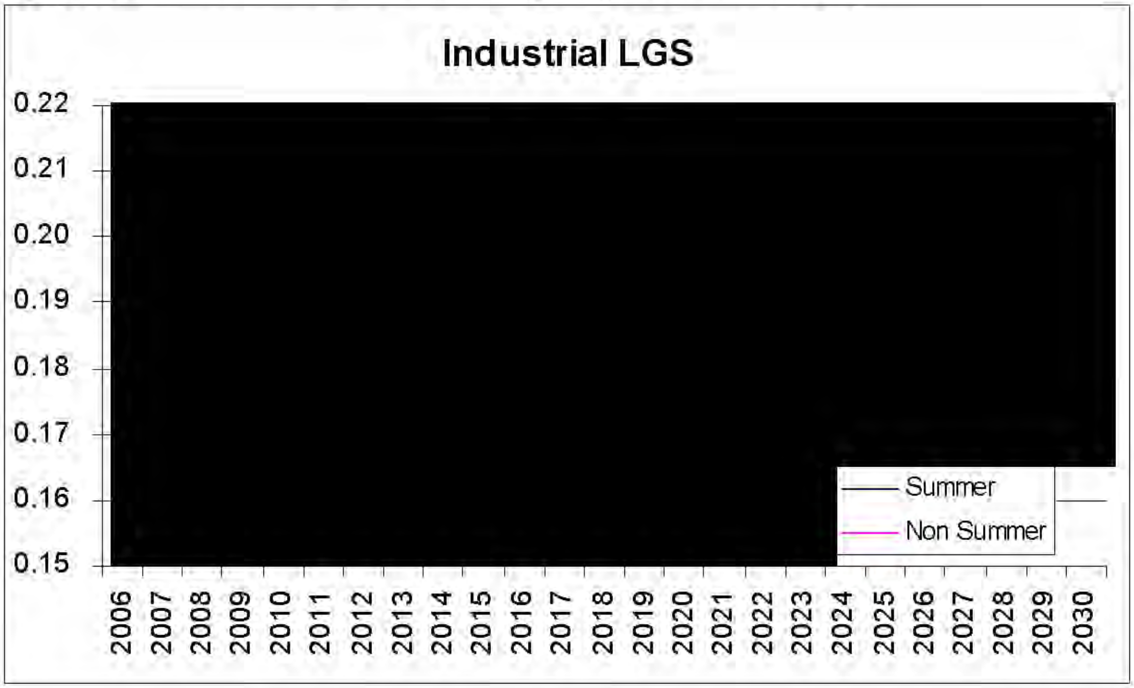


Figure (8)-81: Industrial SPS coincident peak-per-customer (MW)

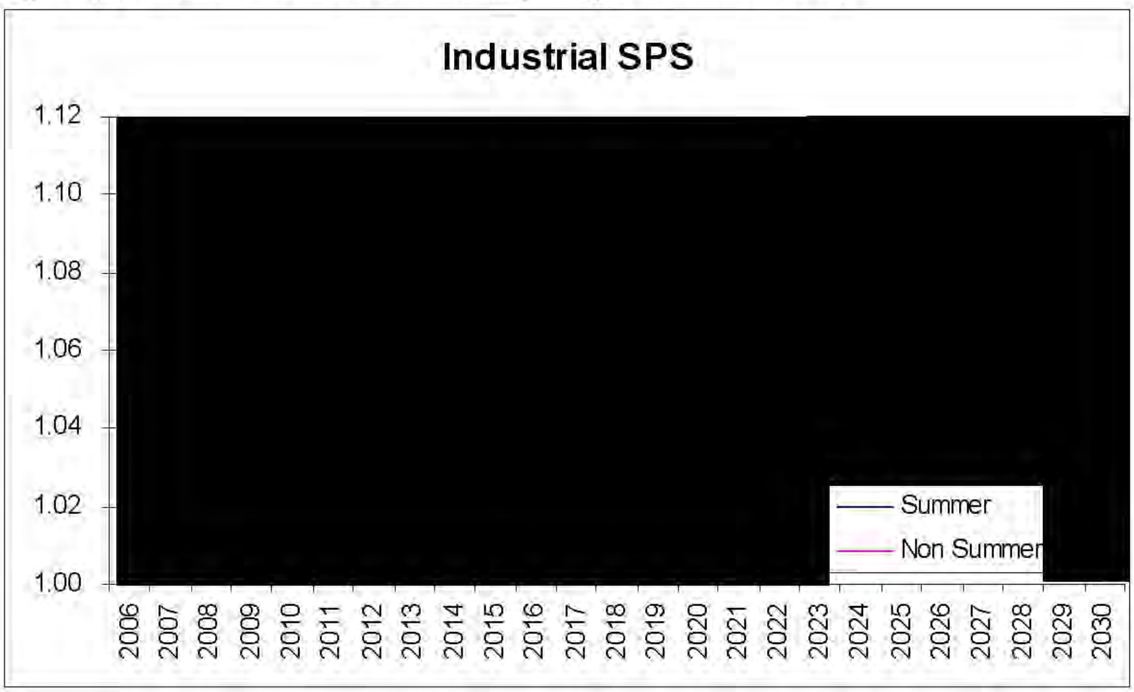


Figure (8)-82: Industrial LPS coincident peak-per-customer (MW)

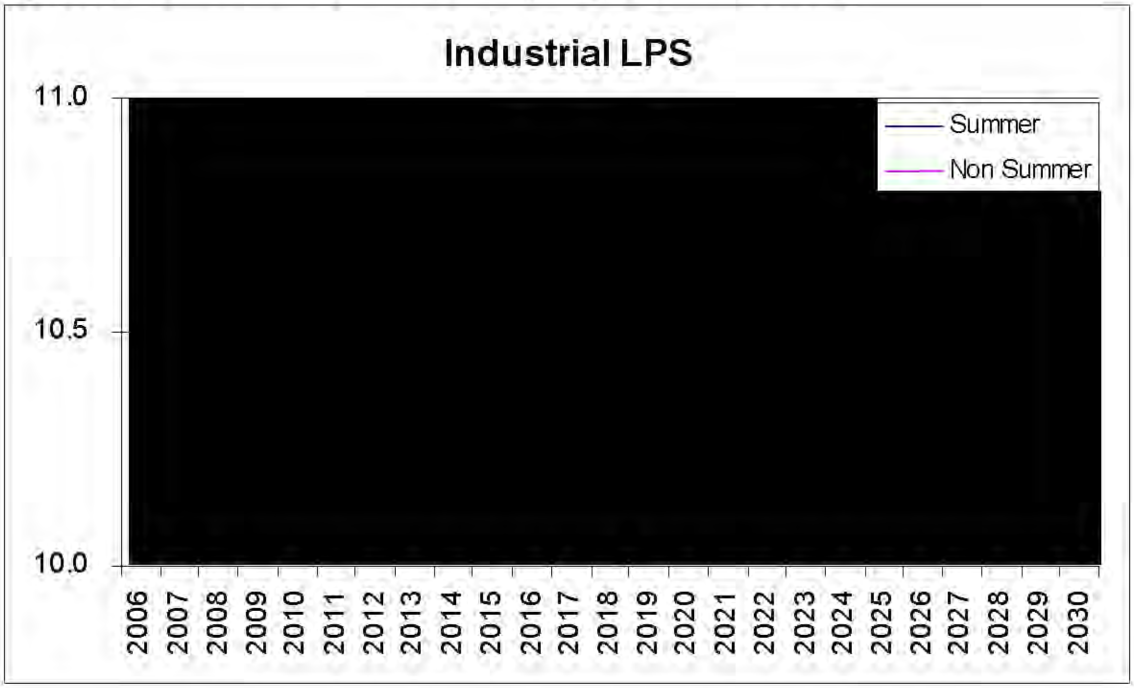


Figure (8)-83: Wholesale coincident peak-per-customer (MW)

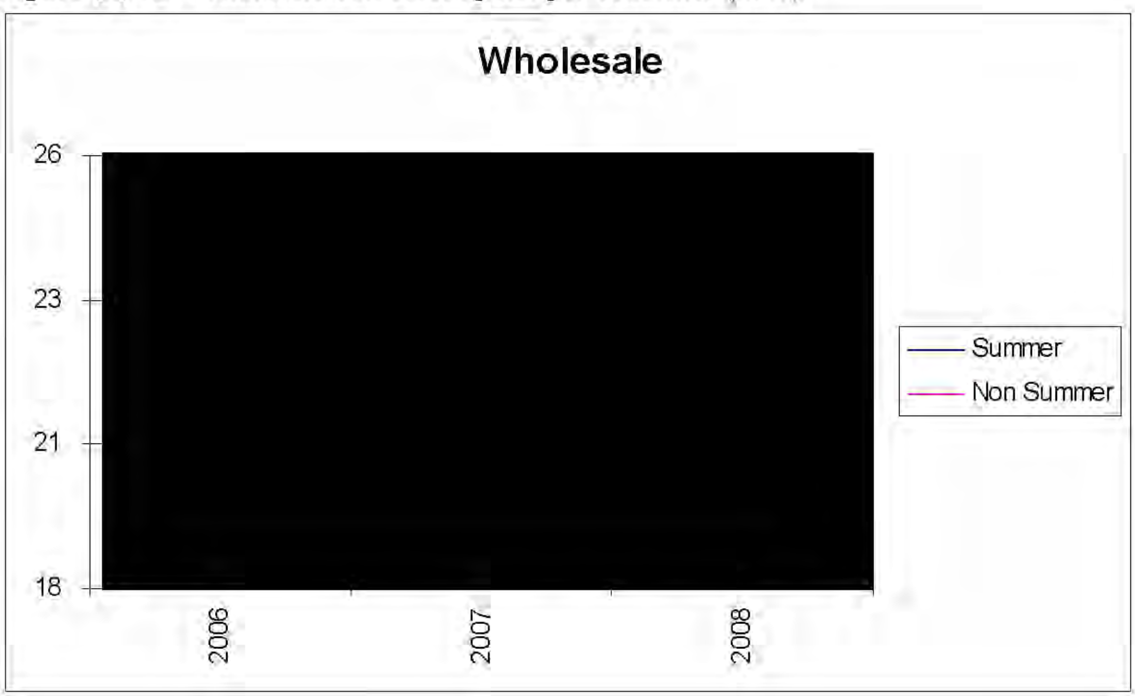


Figure (8)-84: Lighting coincident peak-per-customer (MW)

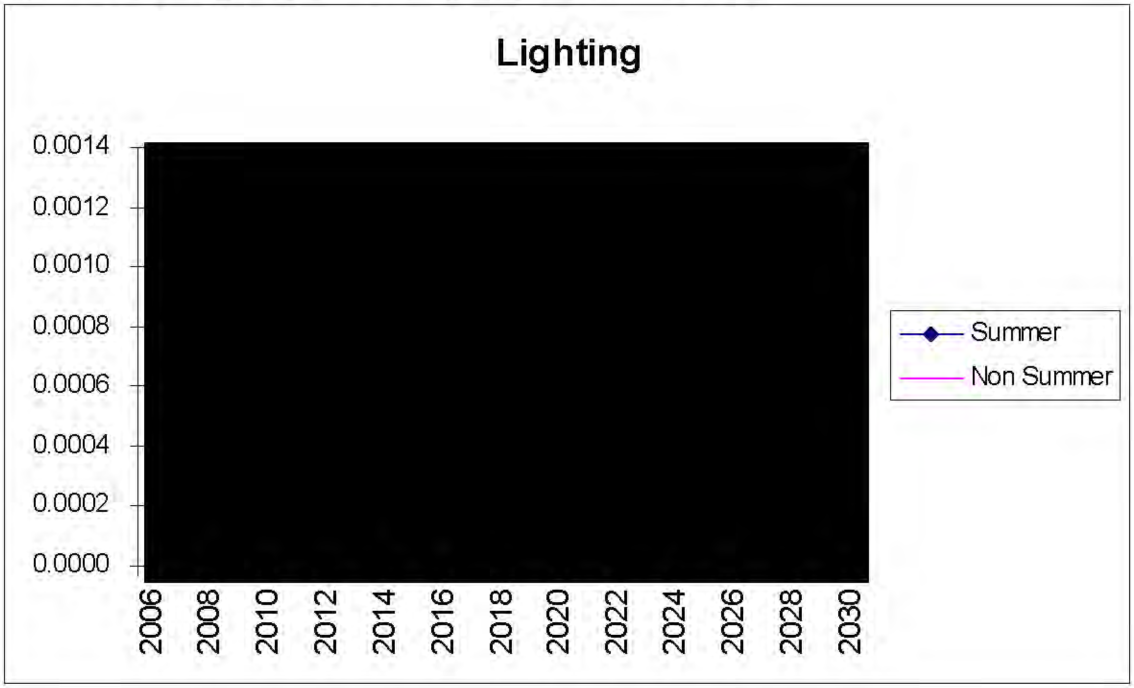


Figure (8)-85: Coincident class peaks (MW)

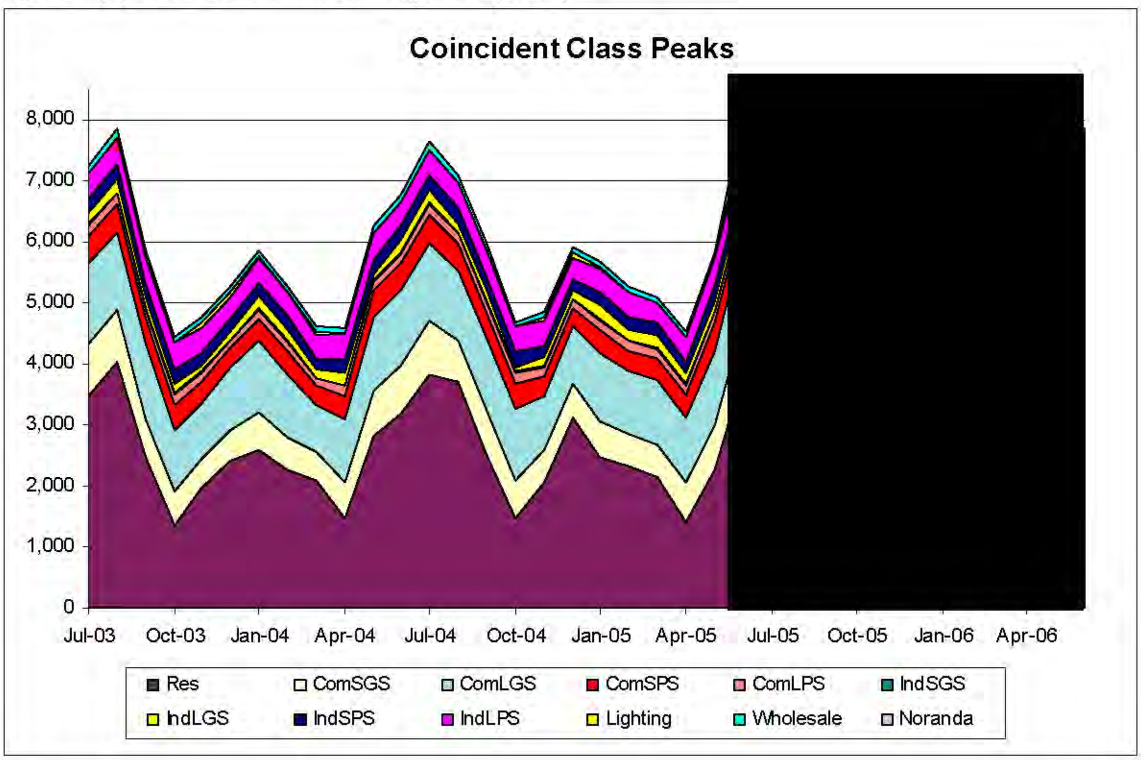


Figure (8)-86: Weather-normalized coincident class peaks (MW)

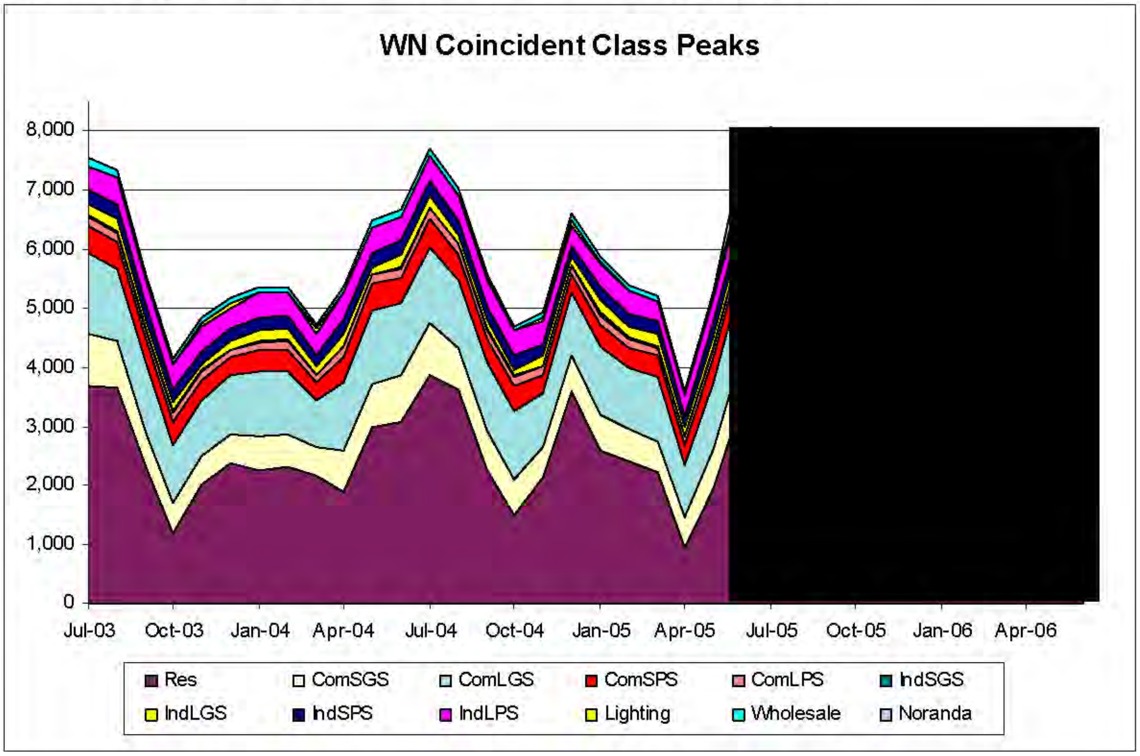


Figure (8)-87: Residential heating-use coincident peak(MW)

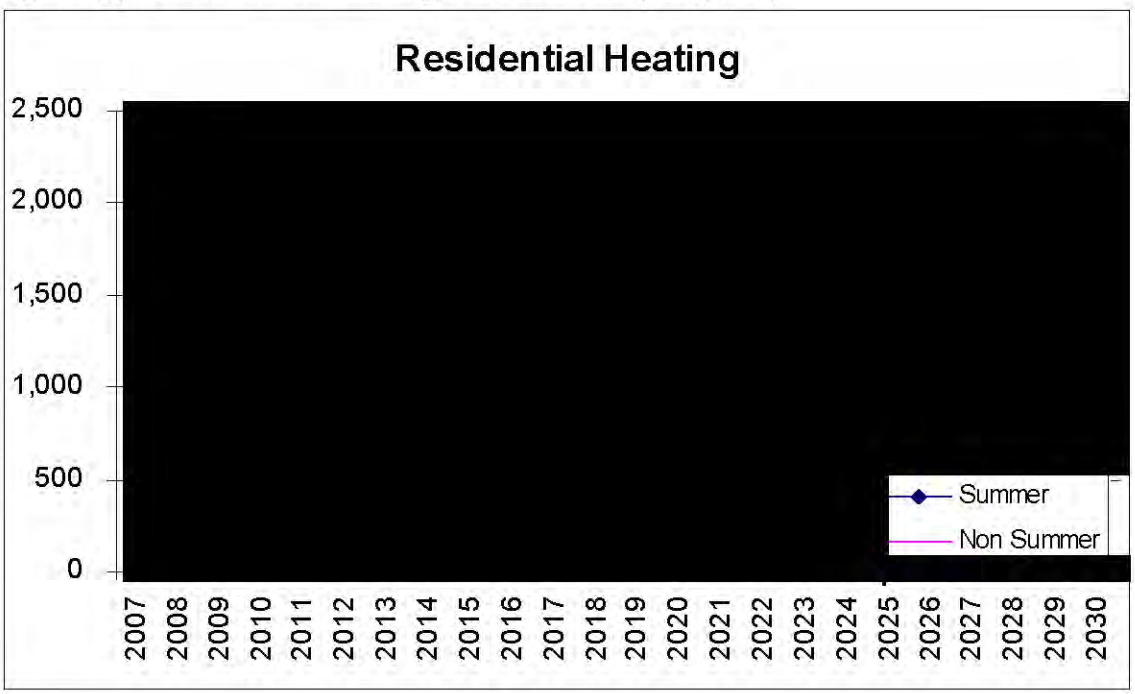


Figure (8)-88: Residential cooling-use coincident peak (MW)

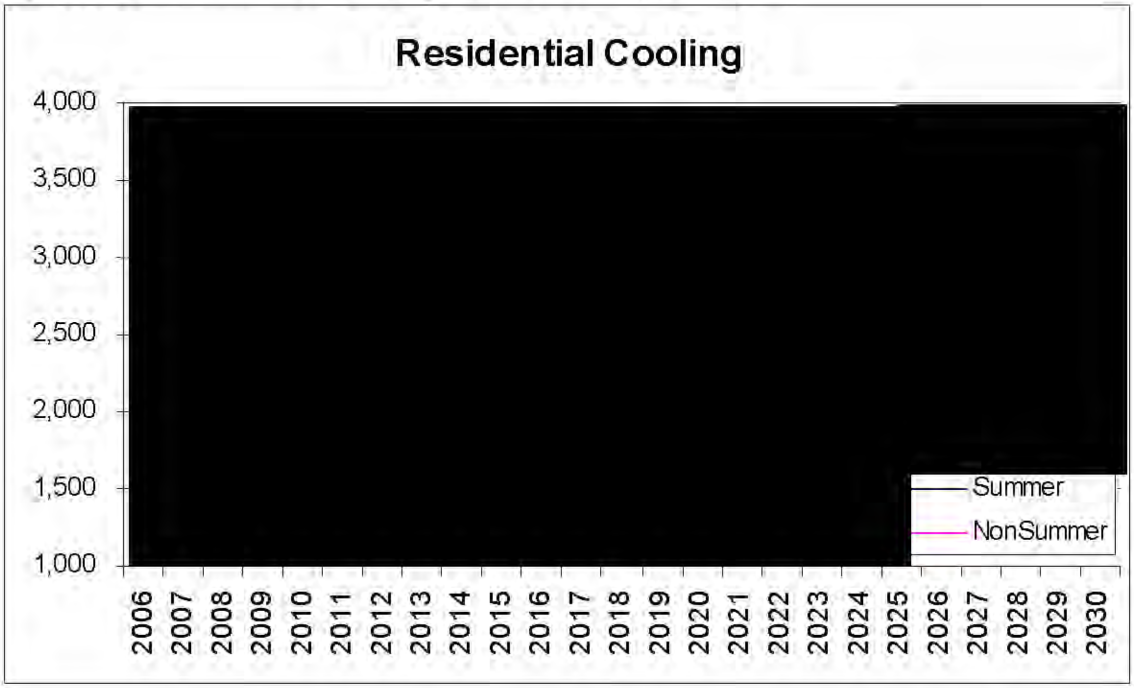


Figure (8)-89: Residential other-use coincident peak (MW)

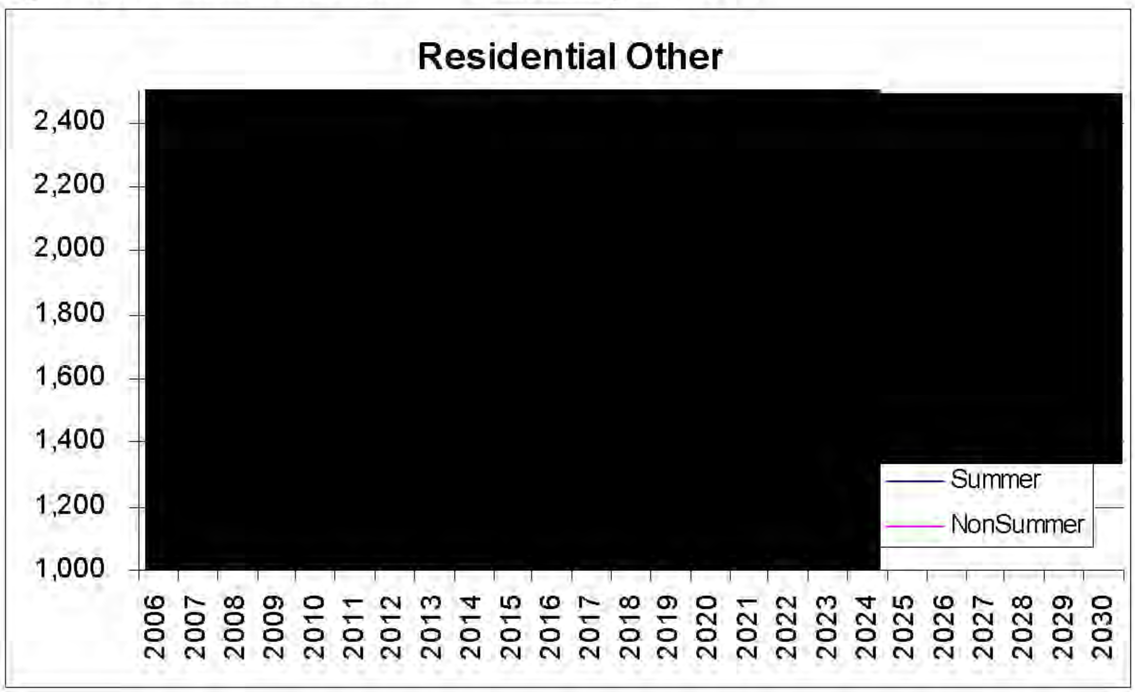


Figure (8)-90: Residential coincident peak (MW)

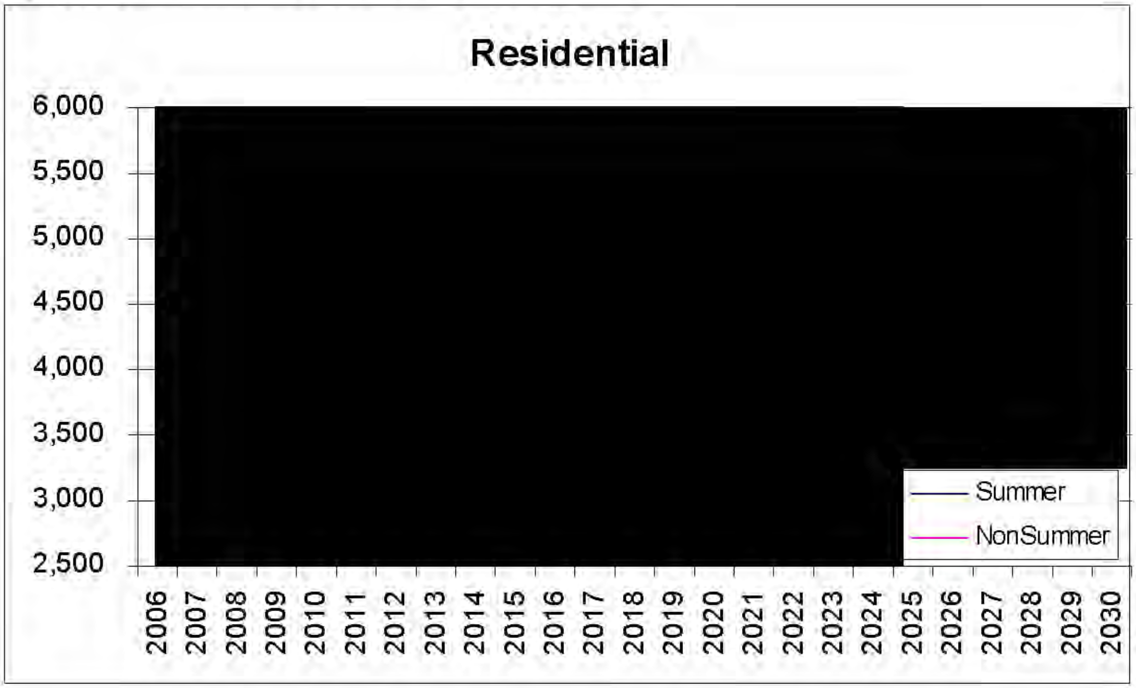


Figure (8)-91: Commercial SGS coincident peak (MW)

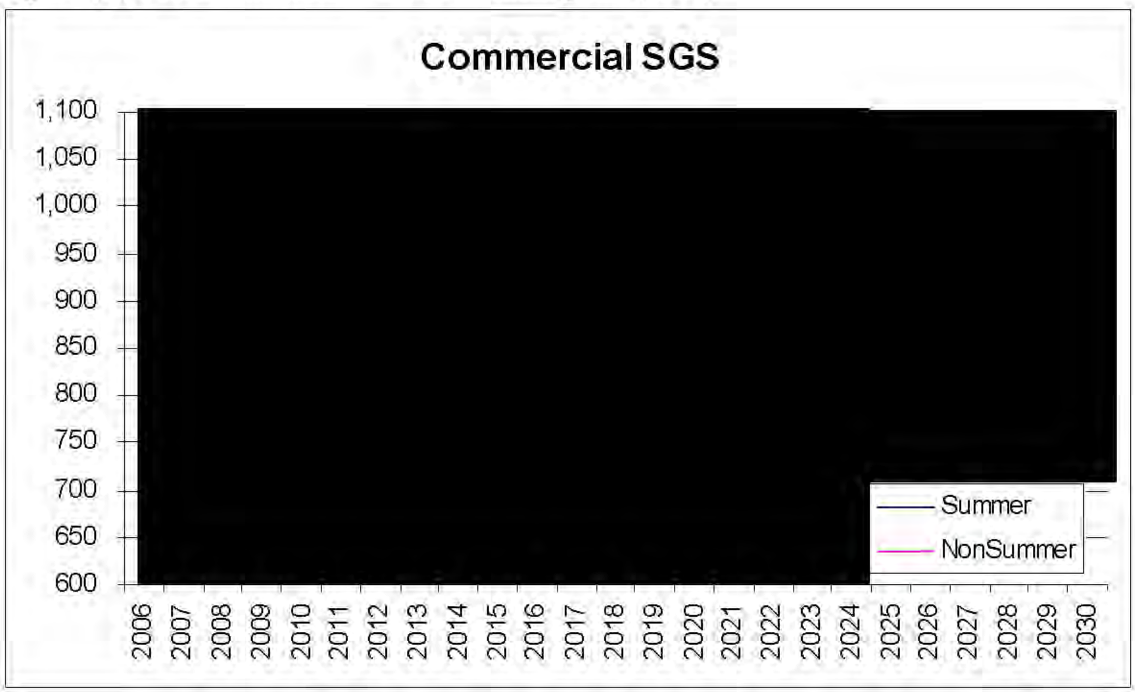


Figure (8)-92: Commercial LGS coincident peak (MW)

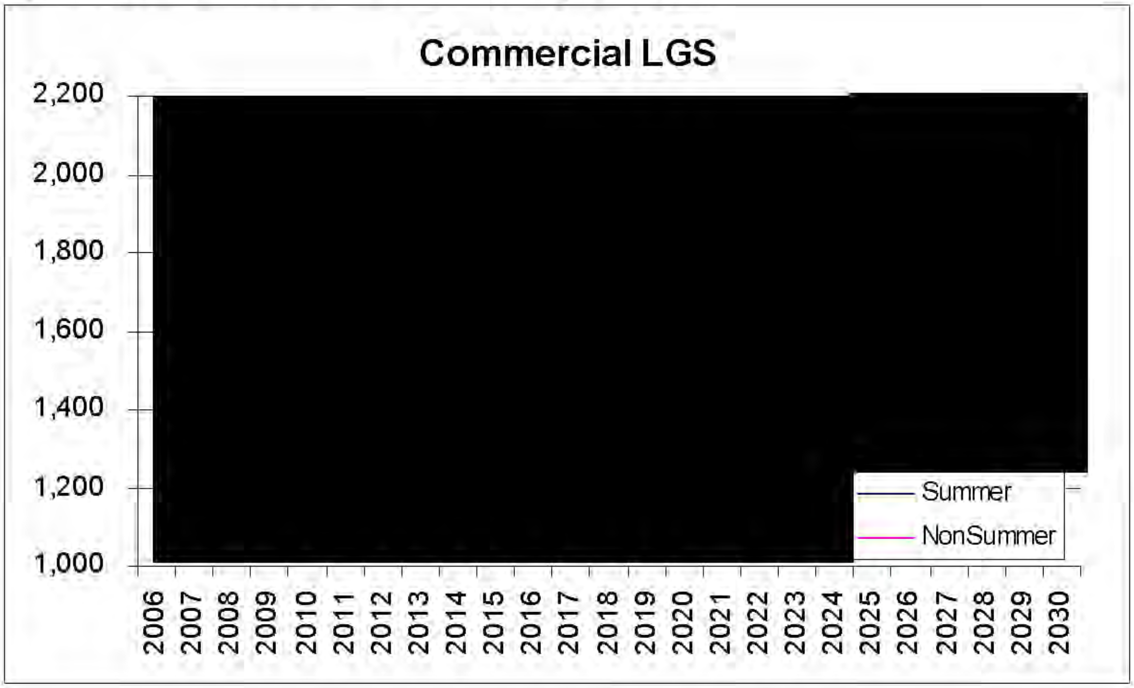


Figure (8)-93: Commercial SPS coincident peak (MW)

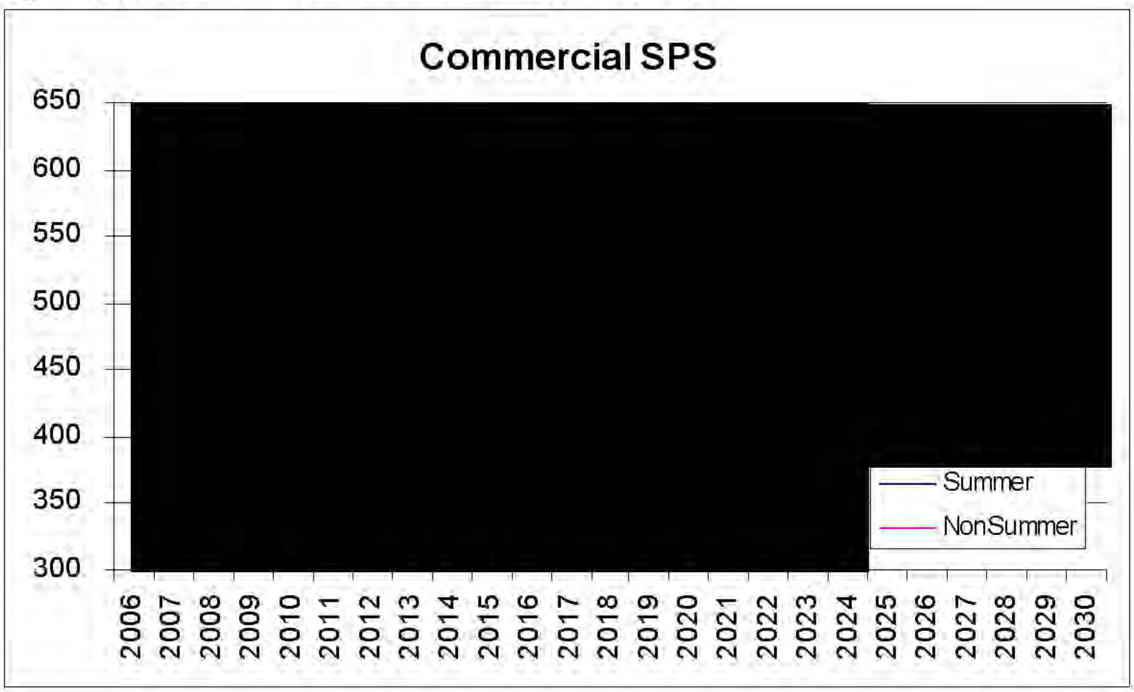


Figure (8)-94: Commercial LPS coincident peak (MW)

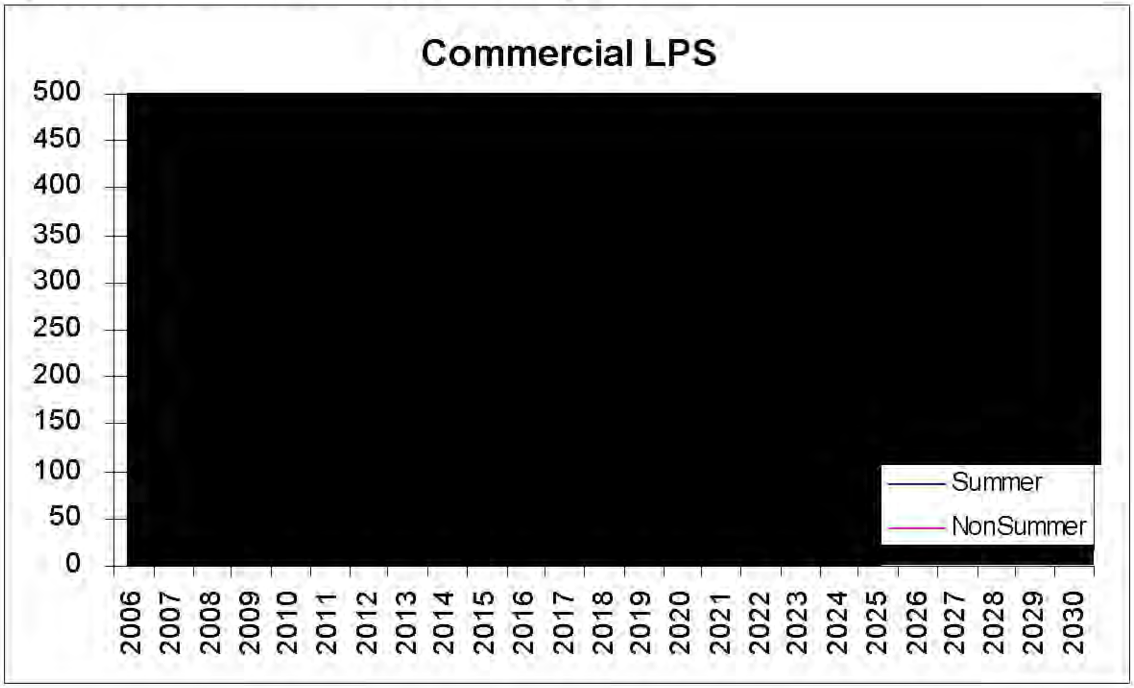


Figure (8)-95: Industrial SGS coincident peak (MW)

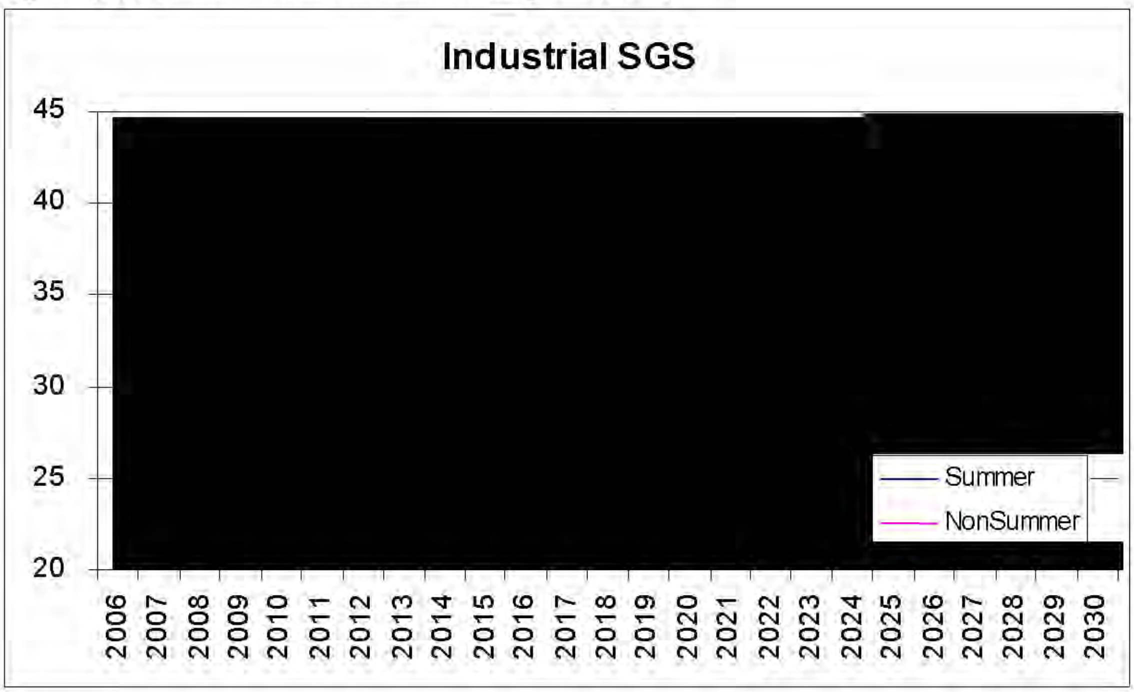


Figure (8)-96: Industrial LGS coincident peak (MW)

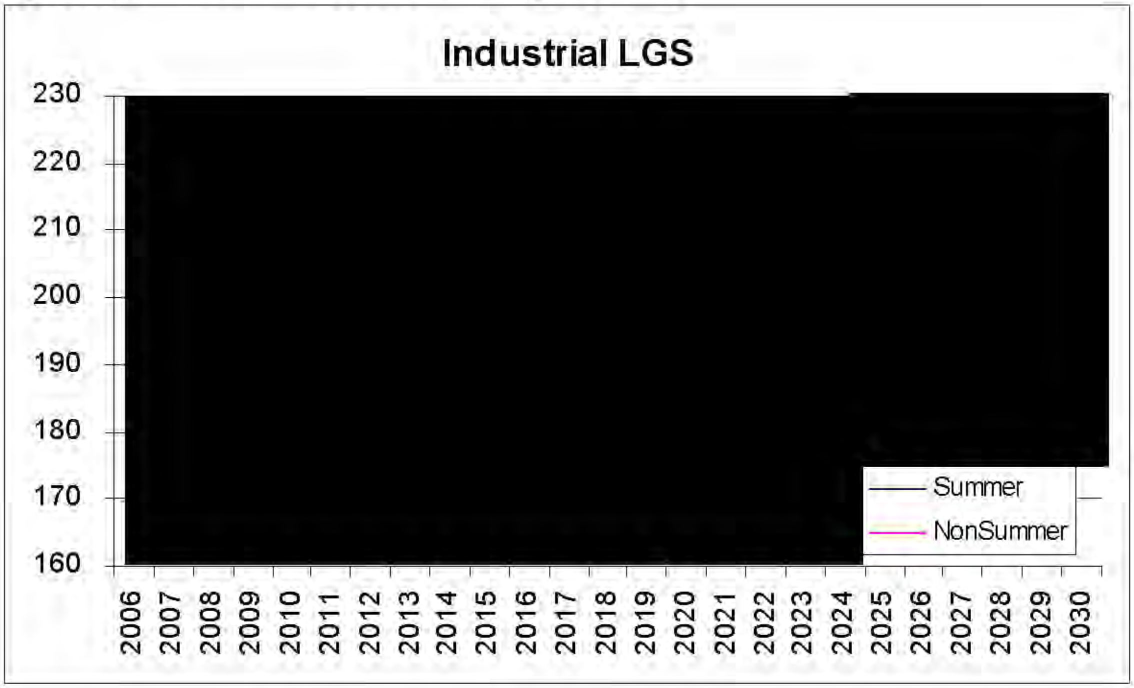


Figure (8)-97: Industrial SPS coincident peak (MW)

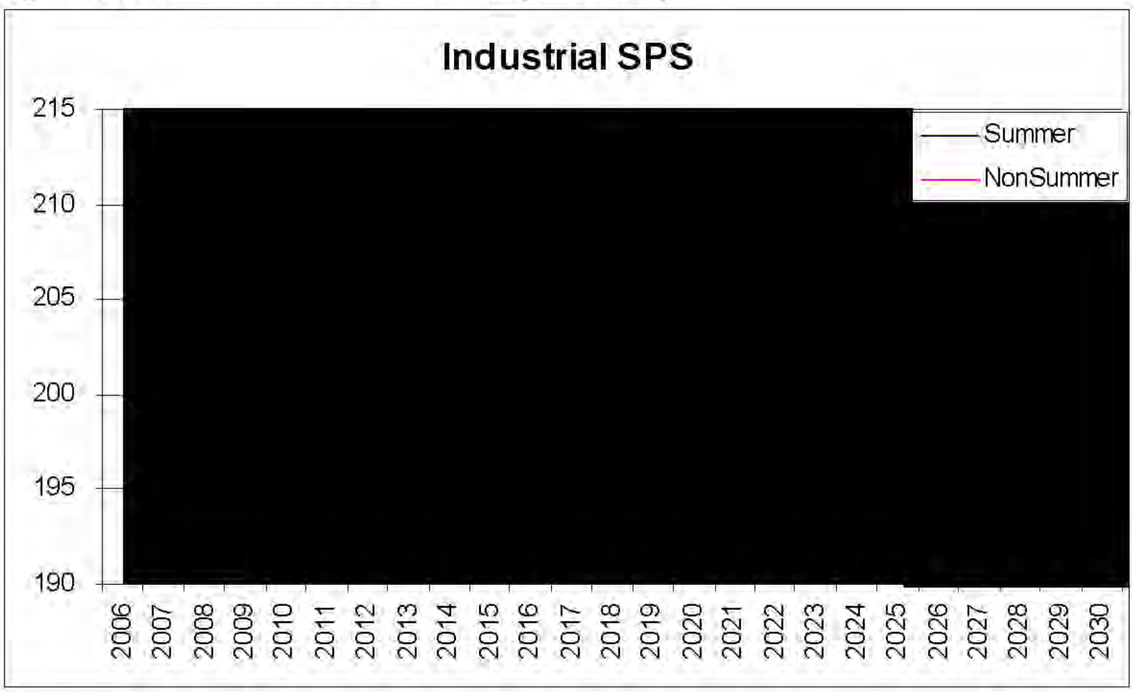


Figure (8)-98: Industrial LPS coincident peak (MW)

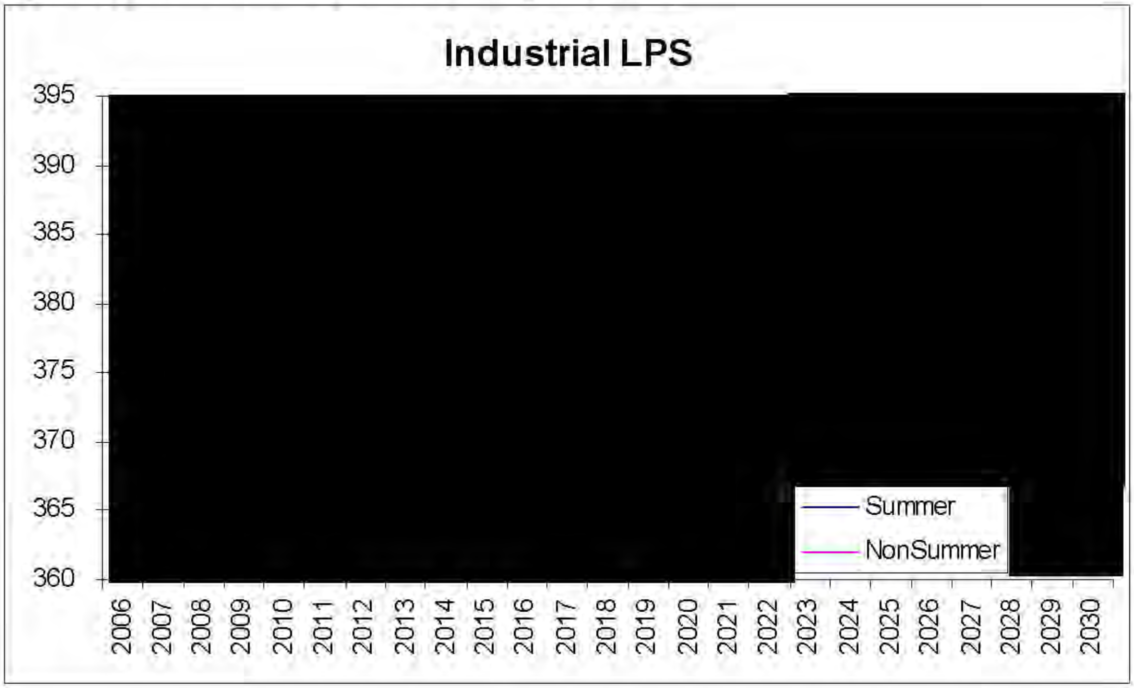


Figure (8)-99: Noranda coincident peak (MW)

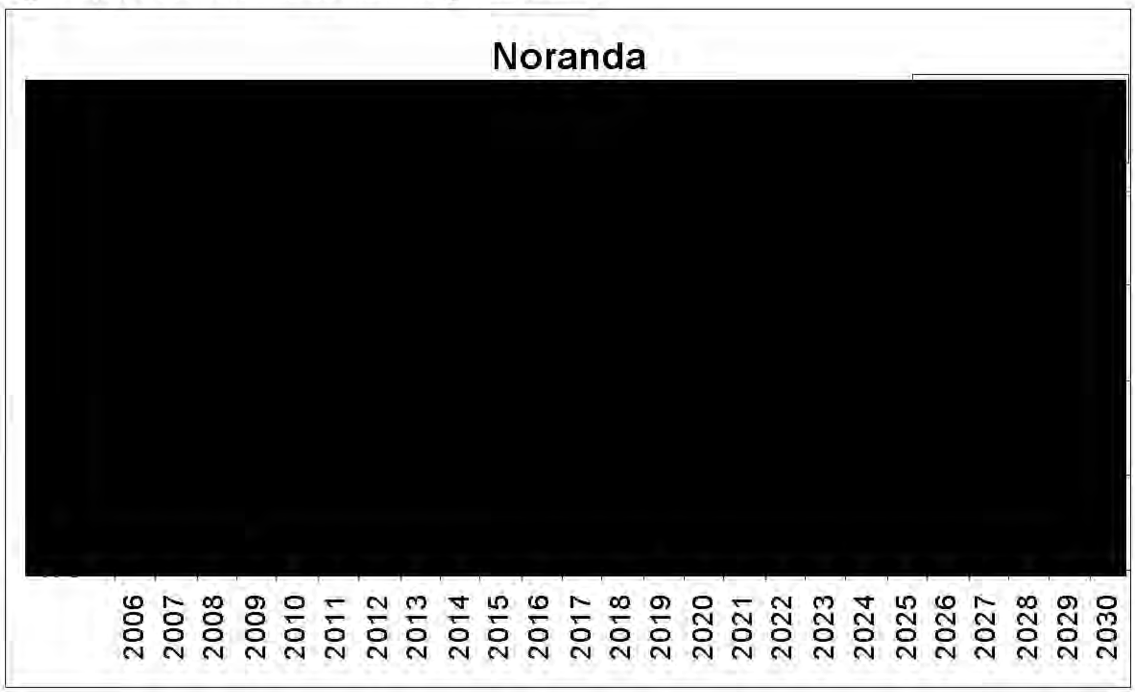


Figure (8)-100: Wholesale coincident peak (MW)

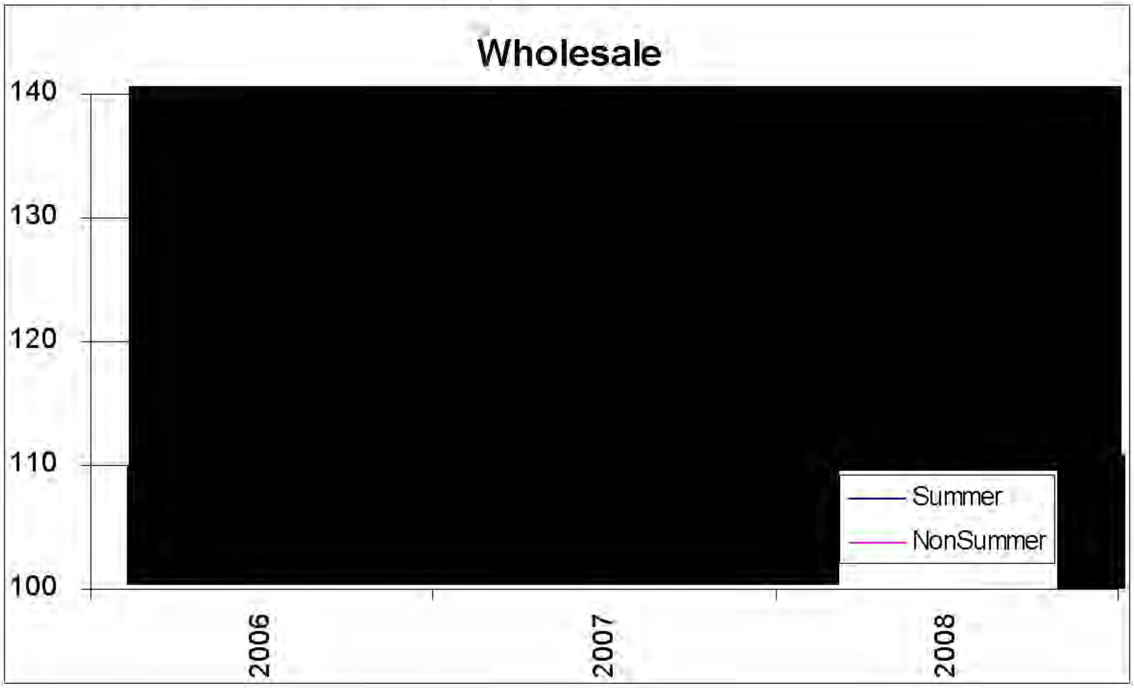
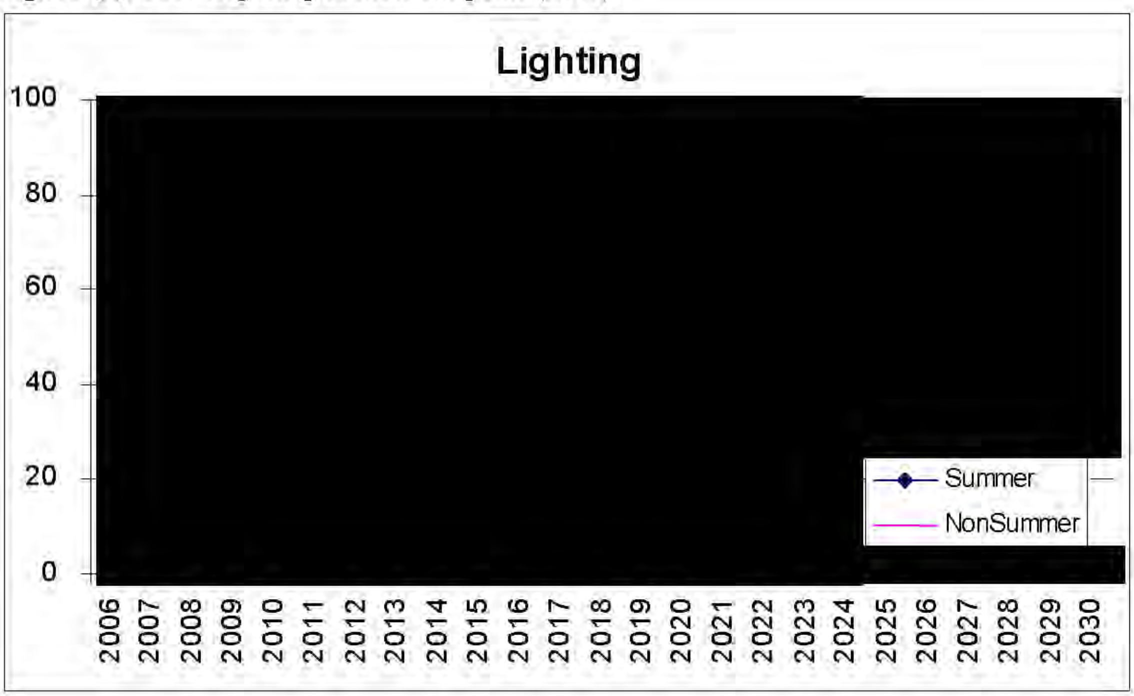


Figure (8)-101: Lighting coincident peak (MW)



4 CSR 22.030 (8) (C)

(C) For the forecast of energy and peak demands, AmerenUE will provide a summary of the range of load forecasts that are reflected in the probability tree of scenarios and the subjective probabilities that are assigned to each of the load forecast cases based on their probabilities as part of the probability tree.

See the response to section 4 CSR 240-22.030 (7) for an explanation of the load forecast cases included in the probability tree. In addition, **Error! Reference source not found.** of Appendix B provides the percentage changes in Eastern Missouri demand from the BAU case for each of the eight other scenarios. AmerenUE used these percentage changes in the strategy selection phases of the IRP process.

4 CSR 22.030 (8) (D)

(D) For the net system load, the utility shall provide plots of energy usage and peak demand.
1. The energy plots shall include the summer, nonsummer and total energy usage for each calendar year.
2. The peak demand plots shall include the summer and winter peak demands.
3. The plots shall cover the historical data base period and the forecast period of at least twenty (20) years. The historical period shall include both actual and weather-normalized values. The forecast period shall include the base-case, low-case and high-case forecasts.
4. The utility shall describe how the subjective probabilities assigned to each forecast were determined.

Figure (8)-102: Total system energy (Calendar month - GWh)

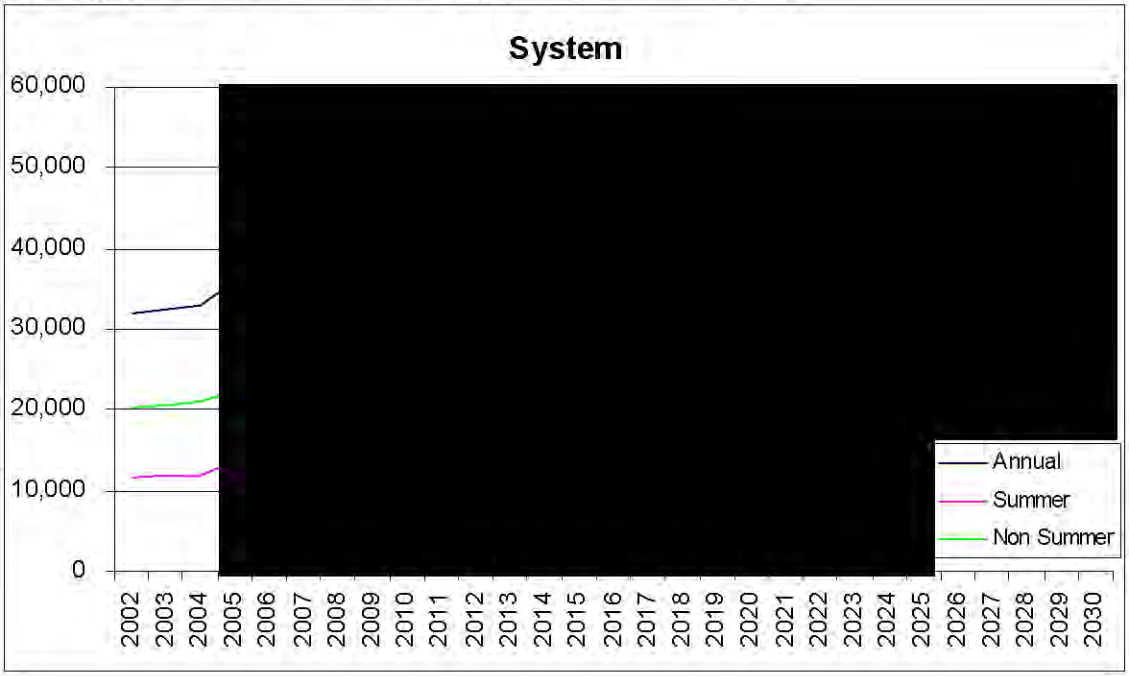
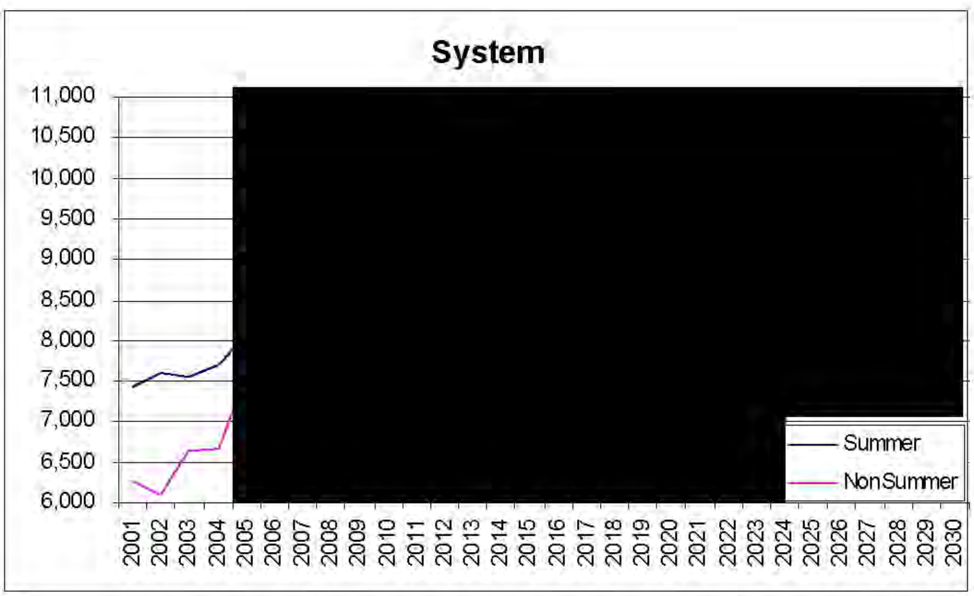


Figure (8)-103: System peak (MW)



Please refer to 4 CSR 240-22.030 (7) for the subjective probabilities.

4 CSR 240-22.030 (8) (E)

(E) For each major class, the utility shall provide estimated load profile plots for the summer and winter system peak days.

1. The plots shall show each end-use component of the hourly load profile.

2. The plots shall be provided for the base year of the load forecast and for the fifth, tenth and twentieth years of the forecast.

Please see the plots in 4 CSR 240-22.030 (8) (F).

4 CSR 240-22.030 (8) (F)

(F) For the net system load profiles, the utility shall provide plots for the summer peak day and the winter peak day.

1. The plots shall show each of the major class components of the net system load profile in a cumulative manner.

2. The plots shall be provided for the base year of the forecast and for the fifth, tenth and twentieth years of the forecast.

Figure (8)-104: 2007 winter peak day profiles (MW)

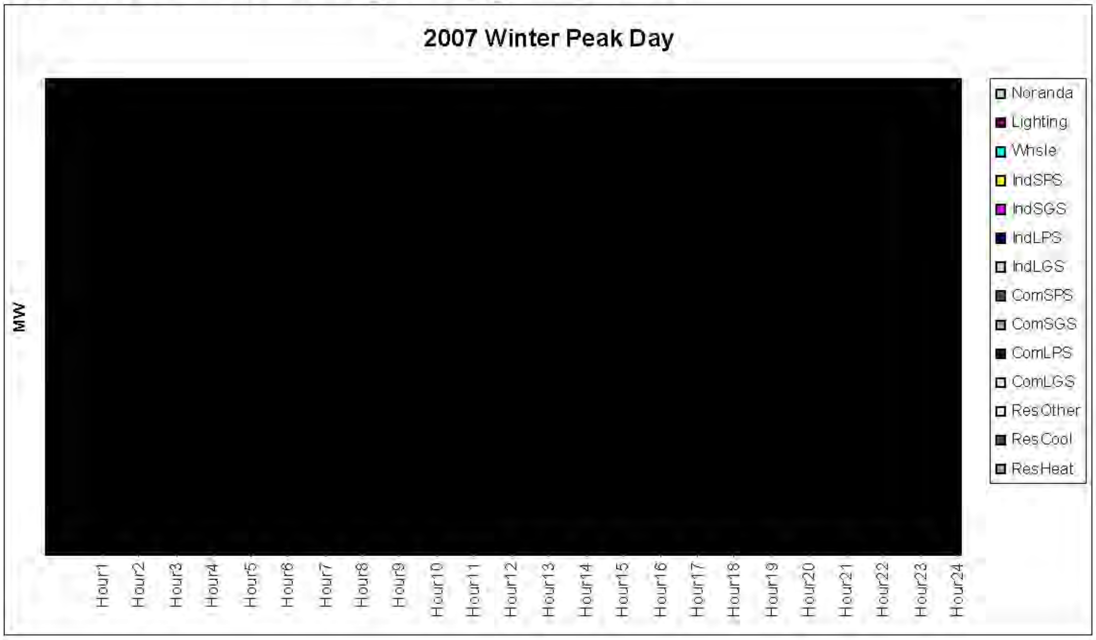


Figure (8)-105: 2007 summer peak day profiles (MW)

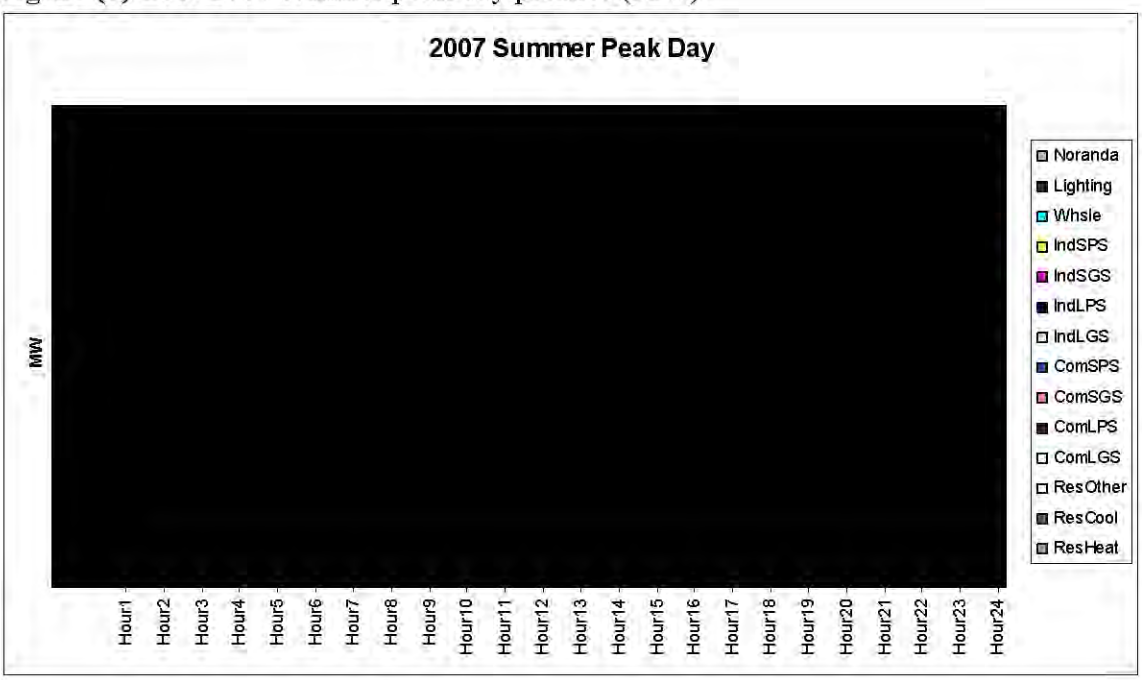


Figure (8)-106: 2011 winter peak day profiles (MW)

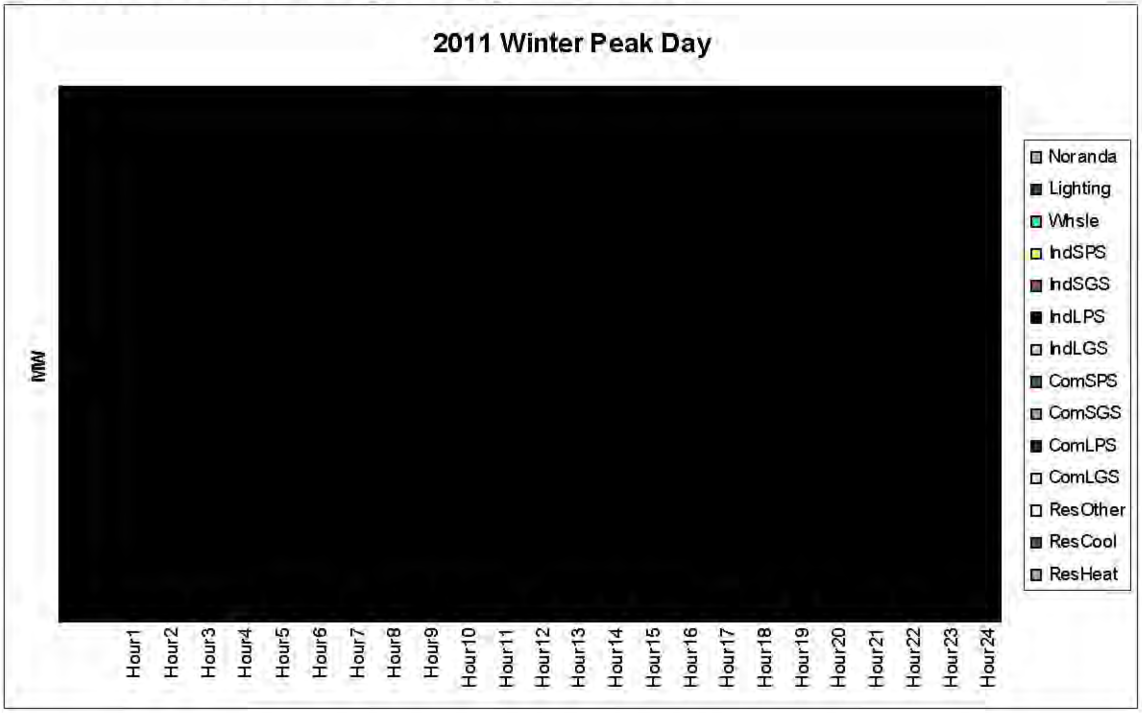


Figure (8)-107: 2011 summer peak day profiles (MW)

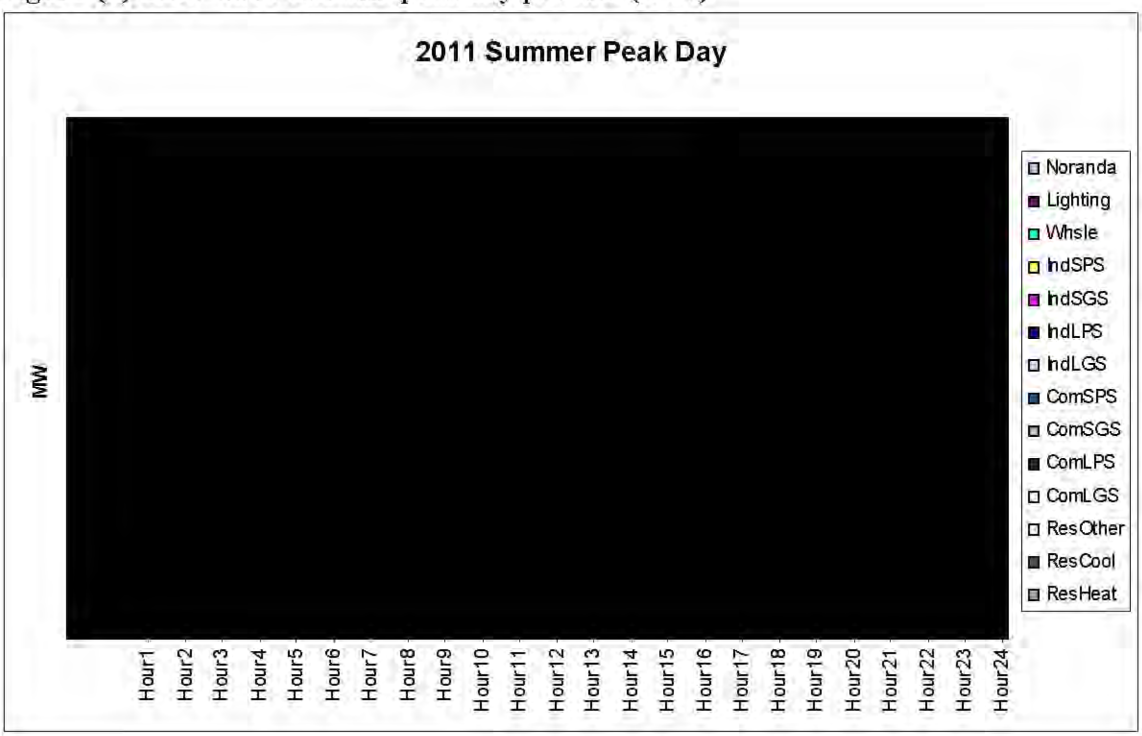


Figure (8)-108: 2016 winter peak day profiles (MW)

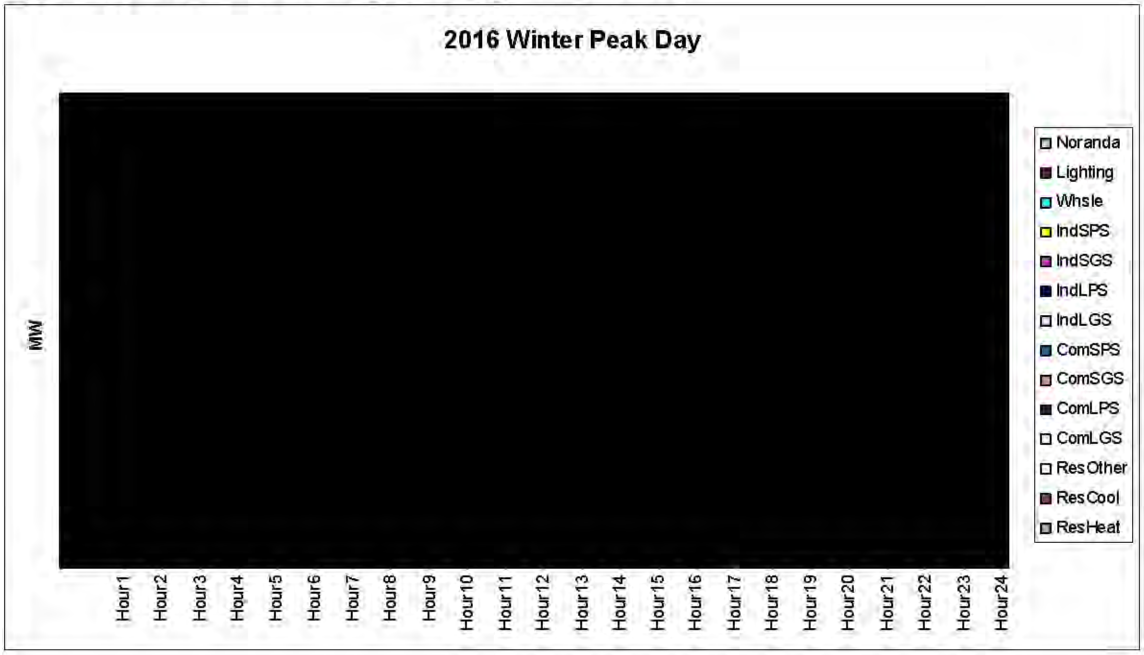


Figure (8)-109: 2016 summer peak day profiles (MW)

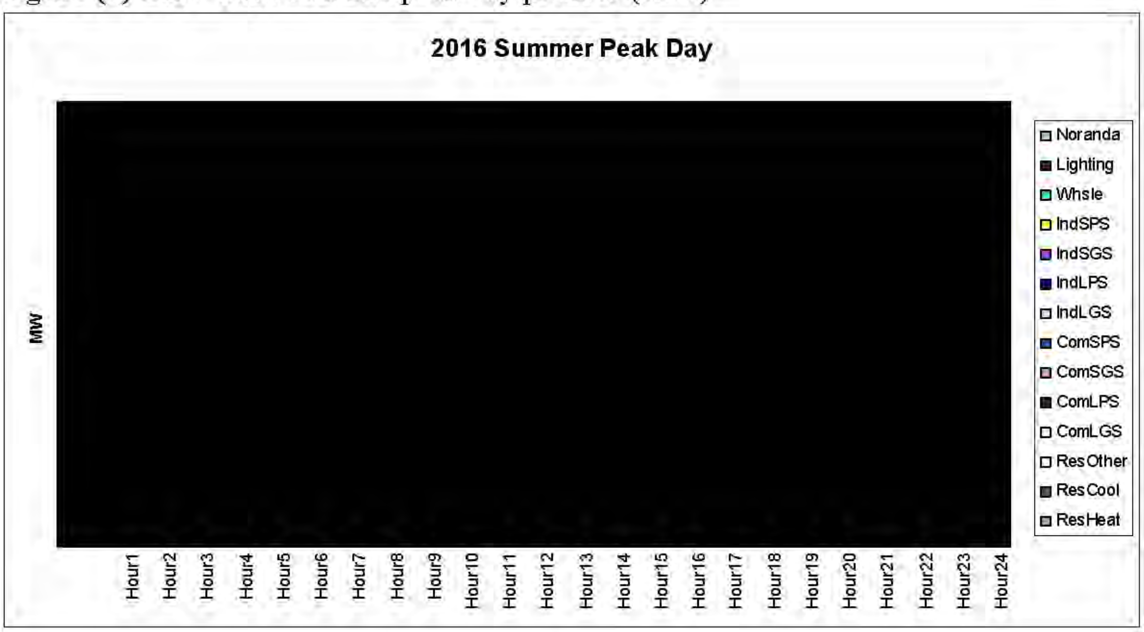


Figure (8)-110: 2026 winter peak day profiles (MW)

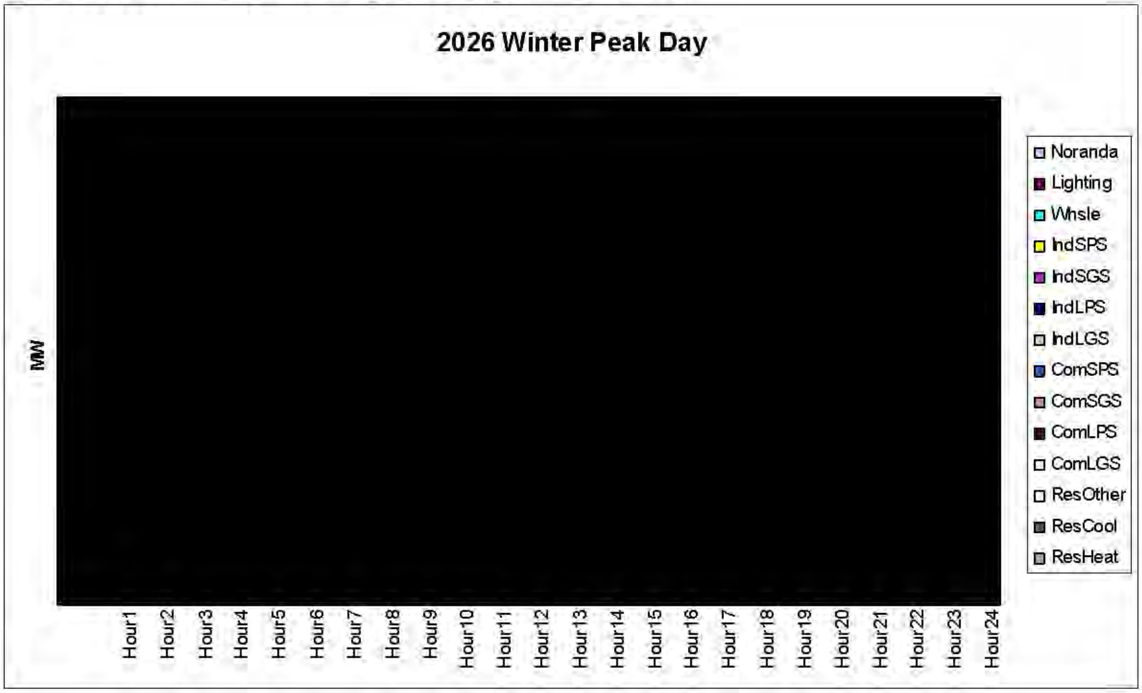


Figure (8)-111: 2026 summer peak day profiles (MW)