Developing Confidence Intervals for the AESO's Long-term Load Forecast

—Methodology and Results—




Results and Analysis prepared for:

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Table of Contents

List of Figures & Tables

Introduction

The Alberta Electric System Operator (“AESO”) has identified the need to develop confidence intervals around its long-term load forecast. For the purpose of various transmission development analyses and regulatory requirements, the AESO acknowledges that there is uncertainty inherent in any long-term load forecast. The AESO therefore requires, along with its long-term load forecast, high and low bookends, the band within which constitutes a reasonable expected range for the forecast. The underlying assumptions for the bookends must be explained, along with why the full range within the bookends contain a relatively likely forecast.

The AESO engaged EDC Associates Ltd. (EDC), and Carter & Associates, to develop and recommend a set of high and low confidence intervals at various levels of confidence, which can be applied to the long-term load forecast presently utilized at the AESO using an appropriate methodology that can be defended in a regulatory setting. The recommendation must be accompanied by a confidence level calculation for each year from 2007 to 2027 or 20 years.

EDC, with input from Carter & Associates, developed the low and high set of forecast confidence intervals from the AESO’s 2007 Forecast (07 Fcst) using the most appropriate modeling techniques, in view of the underlying forecast methodologies and data base used by the AESO to develop its own base case forecast. It should be noted that the scope of the engagement, and the application of the methodologies and techniques used, relate exclusively to the development of the confidence intervals and not to the AESO load forecast itself. The development of the 07 Fcst was undertaken independently by the AESO, and a review of the underlying forecast and its respective methodologies was not performed as part of this engagement.

The following Section provides the scope of work that the AESO established for this study. This is followed by an overview of the methodology employed in developing confidence intervals by sector, and for total Alberta energy and peak demand, and a summary of the results obtained. A brief summary and conclusions is also provided. The Appendix contains detailed tables of the confidence intervals, and provides further explanation of the methodology that was employed to develop the results.

Scope of Work

As part of its Transmission Needs Applications to the Alberta Utilities Commission ("AUC"), the Alberta Electric System Operator ("AESO") expects to complete transmission plans for scenarios that cover the range of the load forecasts (or, at minimum, the high, base, and low); therefore, these additional forecasts must be well considered and supported.

Accordingly, the AESO has identified the need to develop confidence intervals around its long-term load forecast. For the purpose of various transmission development analyses and regulatory requirements, the AESO acknowledges that there is uncertainty inherent in any long-term load forecast. The AESO therefore requires, along with its long-term load forecast, high and low bookends, the band within which constitutes a reasonable expected range for the forecast. The underlying assumptions for the bookends must be explained, along with why the full range within the bookends contain a relatively likely forecast.

The scope of work for this assignment was established by the AESO:

1) A recommendation on a confidence level methodology that can work at the provincial level, and sub provincial or regional level as well, that must be linked to the base curve input fundamentals presently utilized at the AESO. The recommendation will be accompanied by a confidence level calculation for the each year from 2008 to 2027. The confidence bands will be supported by input variable confidence bands (i.e. probability distributions) incorporated in the calculations.

2) Technology transfer: provide the AESO with the means (tools, or techniques) to conduct similar exercises in the future.

Methodology and Results

AESO's 2007 Energy and Demand Forecast

The confidence interval or forecast band was developed from the AESO's 2007 long-term load forecast ("07 Fcst"). The 07 Fcst is disaggregated into three main categories (residential, farm and commercial/industrial), each with a specific model specification. However, the commercial/industrial category alone accounts for around 85% to 89% of the total forecast load, when system losses are excluded.

The 07 Fcst is an annual energy and peak demand forecast for the Province of Alberta, for both the Alberta Interconnected Electric System ("AIES") and Alberta's Internal Load ("AIL"). The differences between these two demand measures is related to the treatment of: a) the City of Medicine Hat's load that is not part of the AIES; and, b) Behind the Fence Load ("BTF") that is not included in the AIES, which is mainly composed of heavy industrial load supplied by onsite generation. It should be noted that the 07 Fcst does not explicitly include any exports or calculation of losses due to exports. However, in calculating total system losses, the 07 Fcst may implicitly account for losses due to exports. The 07 Fcst was developed using historical data up to 2006, with the first forecast year being 2007 and the last forecast year being 2027.

Energy Forecast Confidence Intervals

The forecast confidence bands were produced for two different confidence levels: 80% and 95%. These intervals cover the actual value being forecast in 80% and 95% of repeated samples, respectively, subject to some errors not being present. Hypothetically, if many forecasts are completed, the actual value of the variable being forecast can be expected to fall inside the bounds 80% or 95% of the time.

The forecast bounds for the 80% confidence interval are described by the P10 and P90 values in the forecast results. The P10 value is a point in the data distribution that is greater than 10% of the measurements and less than the others. That is, 10% of the results are less that the P10 value and 90% are greater. The P90 is the other bound of the 80% confidence interval forecast, where 90% of the results are less than the P90 value and 10% are greater. The same logic applies to the 95% confidence interval where the bounds are defined by P2.5 and P97.5.

A discussion of the derivation of the confidence intervals for each customer category is provided following an overview of the methodology of the 07 Fcst. First a forecast is prepared for each customer category (residential, farm and commercial/industrial). Retail sales are then calculated by subtracting behind the fence load (BTF) from the total energy consumption to arrive at retail sales. Distribution and transmission losses are calculated based on retail sales to determine total AIES energy sales. Finally, BTF is added back to determine AIL energy.

The load factors used in the 07 Fcst were applied to the resulting energy sales intervals to determine the peak AIES and AIL demand (one hour) confidence intervals. To account for factors that can affect the peak demand forecast exclusively, such as instantaneous weather effects and unplanned large load outages, and considering the importance of the demand forecast in transmission planning, an adjustment was completed to account for these additional sources of variance in the peak demand forecast.

Residential Energy Forecast

Excluding system losses, the residential 07 Fcst represents 13% of the 2008 energy forecast. This percentage decreases gradually through the entire forecast period, so that by 2027 residential energy sales are forecast to represent 9.5% of total Alberta energy consumption.

Residential energy sales are forecast according to the following equation in the 07 Fcst:

$$ResEnergy_t = (Pop_t) \times (Customer\ \%_t) \times (AUC_t),$$

Where: Pop is Alberta's population; Customer% is the number of electricity customers as a percentage of population; and, AUC is the average annual consumption per residential customer.

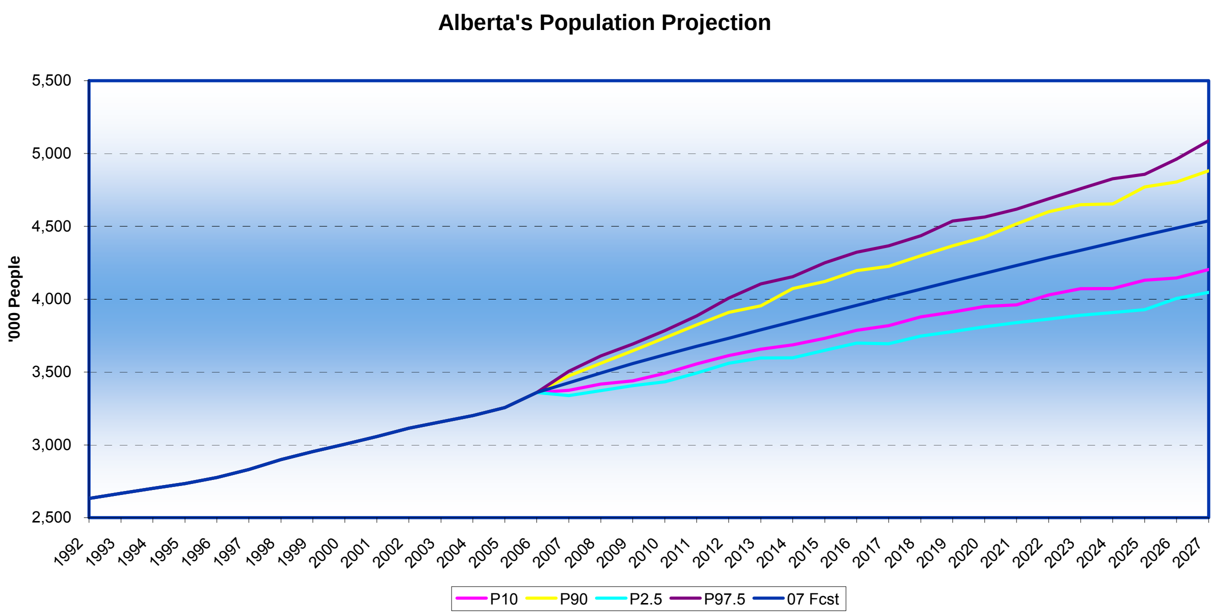
The 07 Fcst relies on the Conference Board of Canada's population forecast. In 2006 Alberta had 1,166,591 residential customers, which divided by Alberta's total population equals 34.72%. This ratio is anticipated to increase over time at a rate of 0.35% per year in the 07 Fcst. This implicitly assumes that the average number of people per household will continue to decrease over time. The 07 Fcst assumes that the average use per customer will be equal to the 11-year average (1996-2006) of 6,930 kWh per customer. By averaging over 11 years of data it is assumed that the forecast is essentially weather normalized, since the historical warmer than normal years would offset the historical colder than normal years. This assumption also recognizes the current trend towards warmer weather, whereby the average number of heating-degree-days per year has been less over the last decade, than it was over the last 20 or 30 years.

Residential Energy Forecast Confidence Intervals

To produce a confidence interval forecast for the residential sector a Monte Carlo simulation approach was used. The above specified energy forecast model was executed 100 times with different values of population, which were derived by substituting different annual population growth rates that were derived from an analysis of historical population growth rates.

The Alberta historical population growth rate was analyzed over the last forty years (1967 – 2006). The average annual population growth rate in Alberta over this period has been 2.1% with a standard deviation of 1.16%. Statistical test indicated that the population growth rate is normally distributed.[1]

Figure 1 - Alberta's Population Confidence Intervals



In the Monte Carlo simulation, 100 runs were performed for every year by generating random growth rates from a normal distribution, with the mean equal to the most likely outcome developed by the Conference Board of Canada's forecast and the calculated historical standard deviation. Because it is very unlikely to have many years of continuous low population growth or continuous high population growth, it was assumed that each year's growth rate would be independent of previous years' growth rates. The compounded population growth rates over 22 years are the combination of random years of low and high population growth. The 100 combinations were thereby derived and the P10, P90, P2.5 and P97.5 levels were calculated. The results are plotted in Figure 1, together with historical population and the 07 Fcst population forecast.

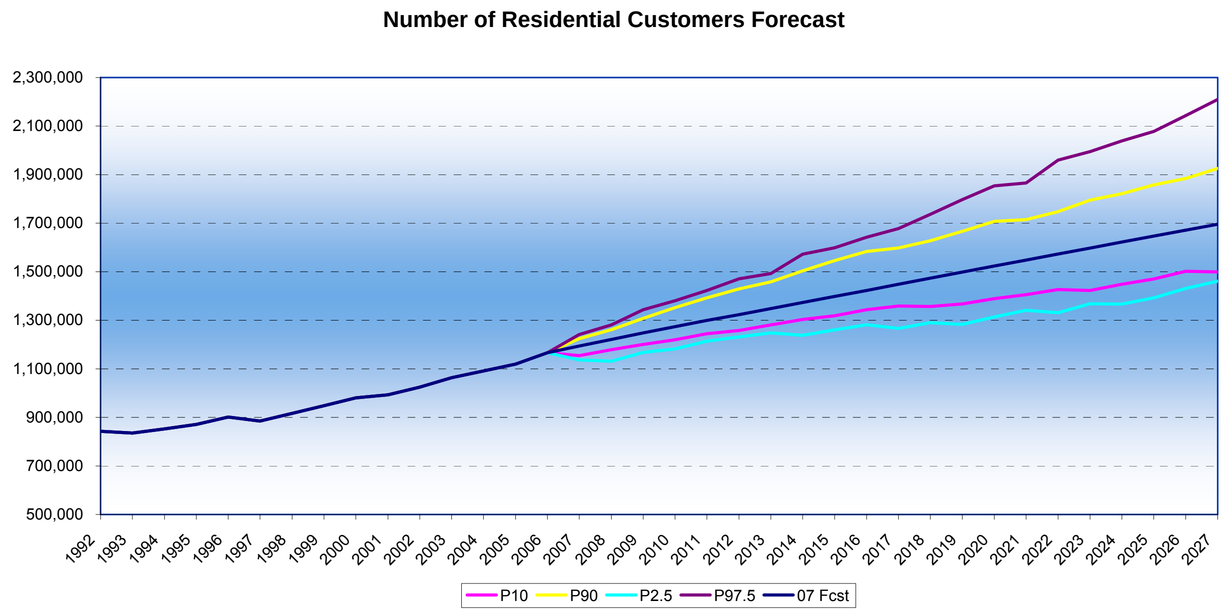
[1] The Jarque-Bera test statistic measures the difference between the skewness and kurtosis of the series with those from the normal distribution. The results indicated that the null hypothesis of normality cannot be rejected at typical confidence levels used in statistical tests. Therefore the distribution in the population growth rate can be assumed to be normal.

After determining the bounds for the population variable, customers as a percentage of population was analyzed in a similar fashion as the population annual growth rate, as a means to develop a distribution to be utilized in the Monte Carlo simulation process.

Over the last 14 years (1993 – 2006), the growth rate of residential customers as a percentage of population has increased by 1.1% per year on average, with a relatively high standard deviation of 1.69%. Test statistics indicated that this variable is not normally distributed. However, for simplicity and considering the relative importance of this variable in the forecast, in the Monte Carlo simulation it was assumed that the growth rate of the percentage of customers relative to total population was normally distributed. In the Monte Carlo simulation the mean was set equal to the most likely outcome, assumed to be the growth rate used in the 07 Fcst (0.35% per year), and the standard deviation equal to the historical standard deviation.

The linear correlation coefficient between historical population growth and the growth of customers as a percentage of population is very close to zero. Because these two variables are not correlated, the customer as a percentage of population growth rate variable was modified independently from the population growth rate variable. This allows for offsetting effects when calculating the number of residential customers, and the two variables can also reinforce the effect of producing very few or many more customers. Figure 2 shows the P10, P90, P2.5, P97.5 values together with the historical and the 07 Fcst number of residential customers. The P-values are the result of combining the effects of the population growth rate Monte Carlo simulation with the customers as a percentage of population simulation.

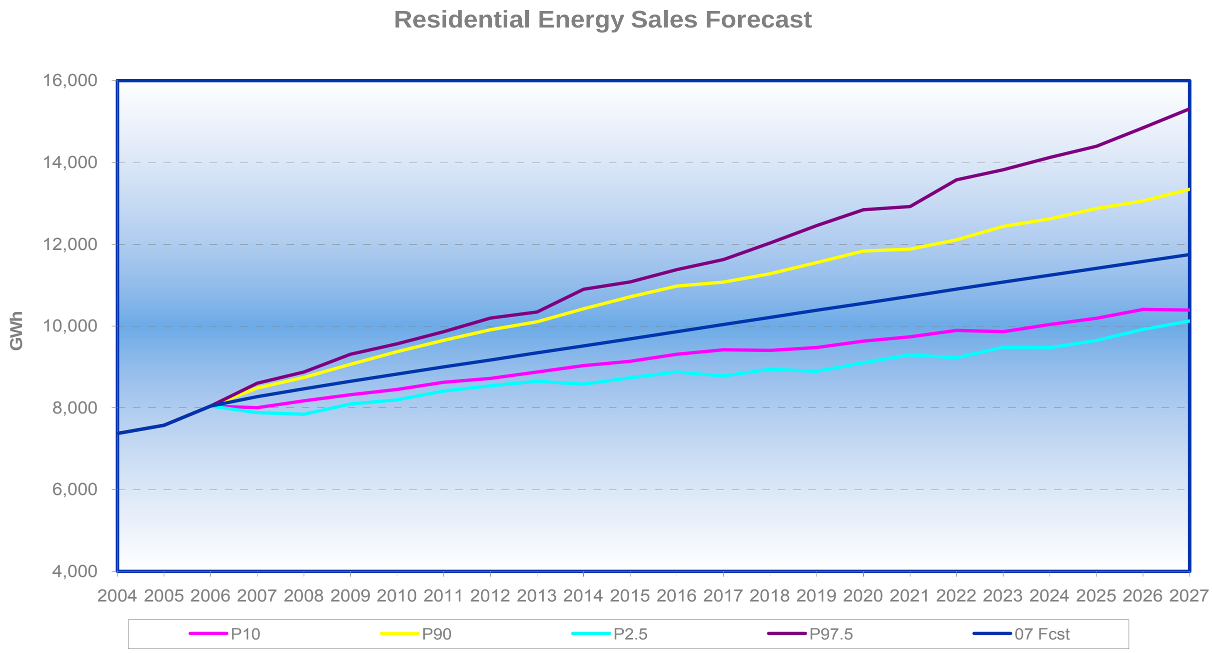
Figure 2 - Number of Residential Customers Confidence Intervals



Finally, the resulting customer numbers at the different P-value levels were multiplied by the average use per customer used in the 07 Fcst to yield the confidence bounds for the residential energy consumption forecast. Different weather scenarios were not simulated in the residential forecast to maintain the weather normalized basis of the original forecast. This was done to maintain a set of consistent assumptions across the entire energy forecast. As outlined below, for the farm sector forecast the weather normalization assumption had to be maintained, because of the different methodology that was employed in generating that sector's forecast.

Figure 3 depicts the P10, P90, P2.5 and P97.5 results for the residential energy forecast, together with the historical data and the 07 Fcst.

Figure 3 - Residential Energy Confidence Intervals



Farm Energy Forecast

Farm energy sales are the smallest customer category. Sales to this sector represented 2.9% of total energy consumption excluding losses in 2007. Like the residential sector, the farm sector's share is anticipated to gradually fall over time reaching 1.8% of total sales by 2027.

This sector's energy consumption is forecast by the AESO according to the following econometric regression:

$$Farm_t = \varphi(HDD_t) + \beta(AGGDP_t) + \eta(CDD_t) + \delta(Farm_{t-1}) + \varepsilon_t$$

Where;

- Farm is the farm sector annual energy consumption,
- HDD is heating-degree-days,
- CDD is cooling-degree-days,
- AGGDP is agricultural GDP,
- ε_t is a independent and identically distributed stochastic error, and
- φ, β, η, δ are the unknown coefficients that were estimated

The 07 Fcst uses ordinary least squares regression using data from 1985 to 2006 to estimate the coefficients. The Conference Board of Canada's forecast for agricultural GDP, together with the 21-year historical average HDD and CDD are used to forecast agricultural energy sales. Using a 21-year historical average for HDD and CDD for the 20 year forecast period essentially ensures that the resulting forecast is weather normalized, as the warmer years offset the effects of colder years in the average.

Farm Energy Forecast Confidence Intervals

To produce the confidence intervals for the farm forecast, it is important to recognize the potential sources of error that exist when using an econometric model to forecast any variable. Four potential sources of error exist:

1. **Specification error:** It may be that the assumptions of the linear regression model being used are not met, in particular that all the relevant explanatory variables are included, that the functional form are

correct and that there have not been structural changes in the market that warrants special consideration.

2. **Conditioning error:** The value of the exogenous variables (e.g. AGGDP) is not known with certainty in the forecast period as it itself is an estimate of the future.
3. **Sampling error:** The estimates of the coefficients are being used instead of the true values (that are unknown) in calculating the energy sales forecast.
4. **Random error:** When calculating the future value of Farm Energy it is assumed that the error term ε_t is zero when its true value may differ considerably from zero.

Ideally the analysis should include and account for the four sources of error when deriving the forecast variance and confidence intervals. Unfortunately, in practice it is usually very difficult to quantify and incorporate all sources of error. Furthermore, since the scope of this study required that the forecast confidence intervals were to be derived given the existing specified forecast models, the issue of specification error was not addressed in this exercise.[2] [3]

Therefore, a traditional statistical approach to deriving the forecast confidence intervals was applied. However, it should be recognized that because this involves ignoring the specification and conditioning sources of error, this leads to the determination of potentially imprecise confidence intervals. In the traditional approach only the sources of error outlined in 3 and 4 above are used to derive the forecast confidence intervals, and it is assumed that the exogenous variables are either known with certainty or forecast without error. Accordingly, the results may understate the true variance. However, given the degree of difficulty involved in the econometric approach the traditional analytic method was used.

Based on the traditional approach, the forecast confidence intervals cover the actual value being forecast in 80% or 95% of repeated samples, assuming no specification or conditioning errors. The variance of the forecast error, from which the confidence interval is constructed, is given by the formula:

$$s^2 + s^2 x_f'(X'X)^{-1} x_f \qquad \ldots(1)$$

where, x_f is a vector of regression observations corresponding to the value of the dependent variable being forecast, and s^2 is the variance of the regression. It should be noted that $s^2\,(X'X)^{-1}$ is the variance-covariance matrix of the Ordinary Least Squares (OLS) estimator. The first term in equation (1) accounts for innovation uncertainty (random error) and the second term for coefficient uncertainty (sampling error). If the innovations are normally distributed, the forecast errors have a *t*-distribution and forecast intervals can be formed. The farm equation used in the 07 Fcst is a special case, in the sense that it has a lagged dependent variable on the right hand side and this generates additional forecast uncertainty. This additional uncertainty is accounted for in the final forecast variance calculation.

To determine if the innovations are normally distributed and the forecast errors distributed as a *t* distribution, the regression residuals were tested. The results indicated that the residuals can be assumed to be normally distributed at conventional statistical levels, and the *t*-statistic could be used to form the forecast confidence intervals.[4]

The confidence interval bands were calculated according to the following formula:

$$\text{Upper/Lower bound}_f = \text{Farm}_f \pm t_{\alpha/2}(\theta) \qquad \ldots(2)$$

Where;

- Farm_f is the forecast for year f,
- $t_{\alpha/2}$ is the *t*-statistic for the α confidence interval, and

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[2] The second source of conditioning error, relates to the fact that the values of the independent variables are forecast, and therefore cannot be accurately addressed. Most econometric texts do not deal with the subject of determining consistent prediction intervals for a forecast when the independent variable is an estimate.

[3] B.D. McCullough, Consistent Forecast Intervals when the Forecast-period Exogenous Variables are Stochastic, Journal of Forecasting, Vol. 15, 293-304 (1996), presents an alternative approach based on the method of bootstrapping to produce consistent forecast intervals when the forecast period exogenous variables are stochastic, noting that the bootstrapping methodology is very laborious and time consuming.

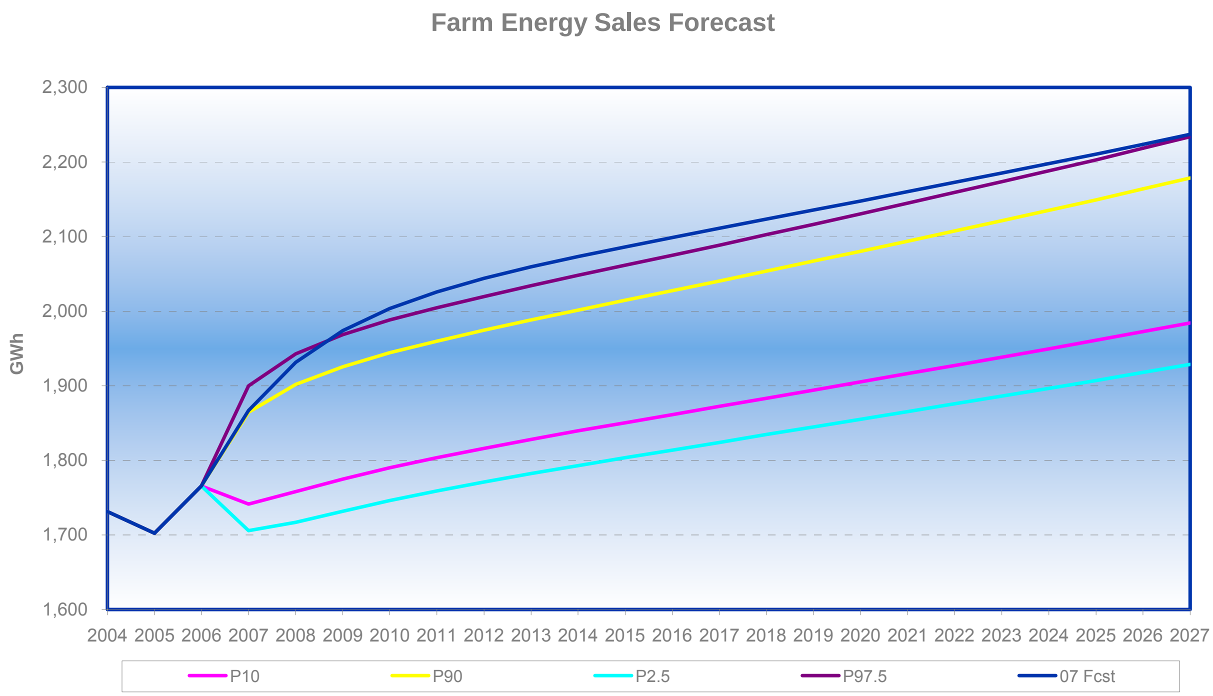
[4] A Jarque-Bera test indicated that the null hypothesis of normally distributed residuals could not be rejected.

- θ is the forecast standard error which is simply the square root of (1).

Figure 4 below shows the results for the farm forecast with the 80% confidence bounds denoted by P10 and P90, and the 95% confidence bounds denoted by P2.5 and P97.5.

It should be reiterated that the forecast bands were derived assuming that the forecast of the exogenous variables is without error. In particular, this implies that the Conference Board of Canada's agricultural GDP forecast is without error and that every year in the forecast will experience the 21-year historical average HDD and CDD. Therefore, the farm energy bands are being derived on weather normalized basis.

Figure 4 - Farm Energy Confidence Intervals



Commercial and Industrial Energy Forecast

The commercial and industrial sectors are forecast together in the 07 Fcst. In 2007, commercial and industrial energy is expected to represent 84% of total energy consumption excluding energy loses. The combined share of these two sectors is anticipated to grow gradually over time reaching almost 89% of total energy consumption by 2027.

The 07 Fcst forecast commercial and industrial energy sales according to the following econometric model:

$$CommInd_t = \beta(GDP_t) + \eta(CommInd_{t-1}) + \varepsilon_t$$

Where;

- CommInd is commercial and industrial sector energy consumption,
- GDP is Alberta's GDP,
- ε_t is a independent and identically distributed disturbance term, and
- β and η are the unknown parameters that were estimated.

Similar to the farm sector, the parameter estimates were obtained using OLS and historical data from 1992 to 2006. The Conference Board of Canada's provincial GDP forecast was used to forecast future industrial and commercial energy consumption.

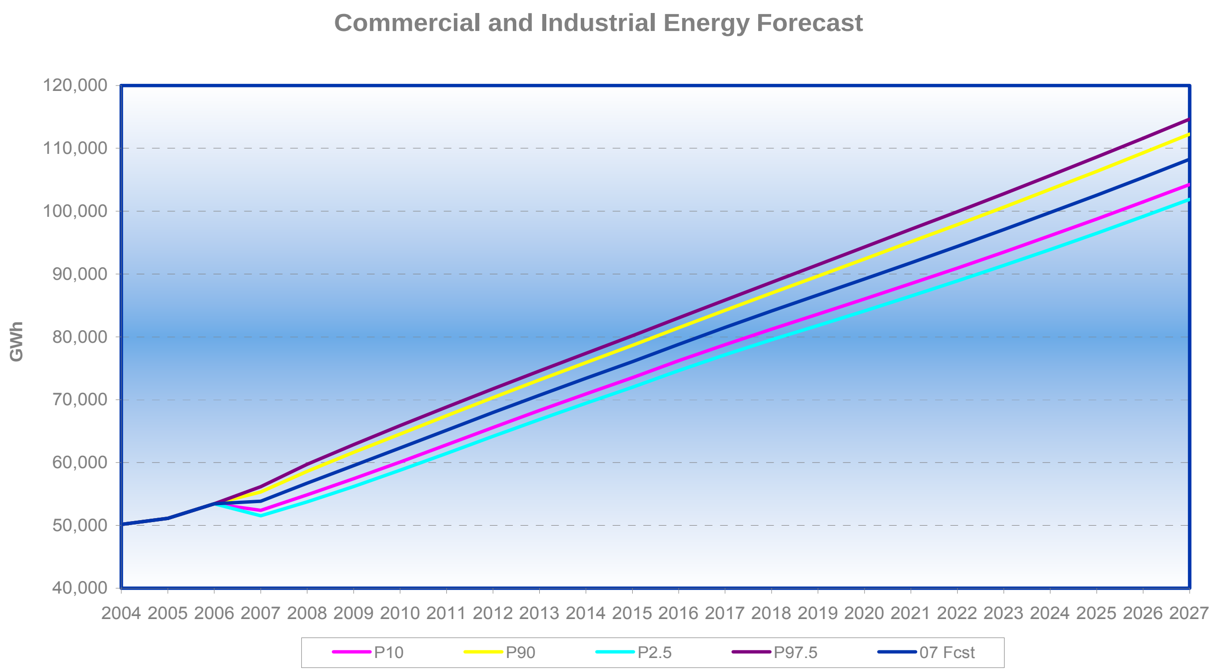
Commercial and Industrial Forecast Confidence Intervals

Because an econometric approach was used to forecast the energy consumption of these sectors, the issue of producing forecast confidence intervals around the 07 Fcst was addressed in the same way as the farm sector. The traditional approach of deriving the forecast variance was used in the derivation of the forecast intervals. This accounts for the variance of two sources of error, sampling and stochastic error, but ignores the specification and conditioning errors for the reasons outlined above. Similar to the farm forecast, the consequence of this is that it produces potentially imprecise forecast bands when the GDP forecast is imprecise and/or if the model is misspecified.

Tests completed on the residuals of the commercial and industrial regression indicated a normal distribution at conventional significance levels.[5] Therefore, the *t*-statistic was used in the calculation of the confidence intervals.

Figure 5 below shows the forecast confidence interval bands for the commercial and industrial energy that were derived using the traditional method. The additional forecast uncertainty generated by the inclusion of the lagged dependent variable as an explanatory variable was also accounted for in the derivation of the forecast bounds. The 80% confidence interval band is delineated by the P10 and P90 values depicted in Figure 5, while the P2.5 and P97.5 are the bounds at the 95% confidence level.

Figure 5 - Commercial and Industrial Energy Confidence Intervals



It should be noted that in absolute terms the calculated standard errors of the forecast increase over time, creating progressively wider forecast bands over time in the future. However, expressed as a percentage of the base 07 Fcst, the lower and upper bounds tend to be constant over time limiting the width of the forecast bands in the distant future. This is primarily the result of using the traditional analytical approach in calculating the confidence interval bands, which does not account for certain sources of error.

AIES and AIL Energy Forecast Confidence Intervals

The Appendix 1 in this report provides the detailed numerical results for the confidence intervals calculated by sector. The Appendix also discusses the reconciliation of the Base Case forecast developed for this Report and

[5] The Jarque-Bera test was used once again to determine if the use of the *t*-statistic was appropriate in the calculation of the confidence intervals. A test statistic on the residuals suggested that the null hypothesis of normality could not be rejected.

AESO 07Fcst. In addition, the Appendix illustrates the steps that were taken in obtaining AIES and AIL energy consumption, and the calculation of transmission and distribution losses.

The addition of transmission and distribution losses to the aggregated retail sales by sector generates the AIES energy sales forecast. These are domestic energy sales that flow through the AIES grid and are traded through the AESO. This excludes exports, which also flow through the grid and are traded through the AESO. The City of Medicine Hat's load is also not included in AIES energy sales and except for what is imported from the AIES is not traded through the AESO. Finally, industrial onsite energy is not included in AIES energy sales. As a result, the BTF energy, which was calculated earlier as a percentage of commercial and industrial energy consumption, is added back to AIES energy to determine AIL energy.[6] AIL energy refers to energy consumed within the province including City of Medicine Hat's load and industrial load supplied by onsite generation, but excludes export sales.

Figure 6 - Domestic AIES Energy Confidence Intervals

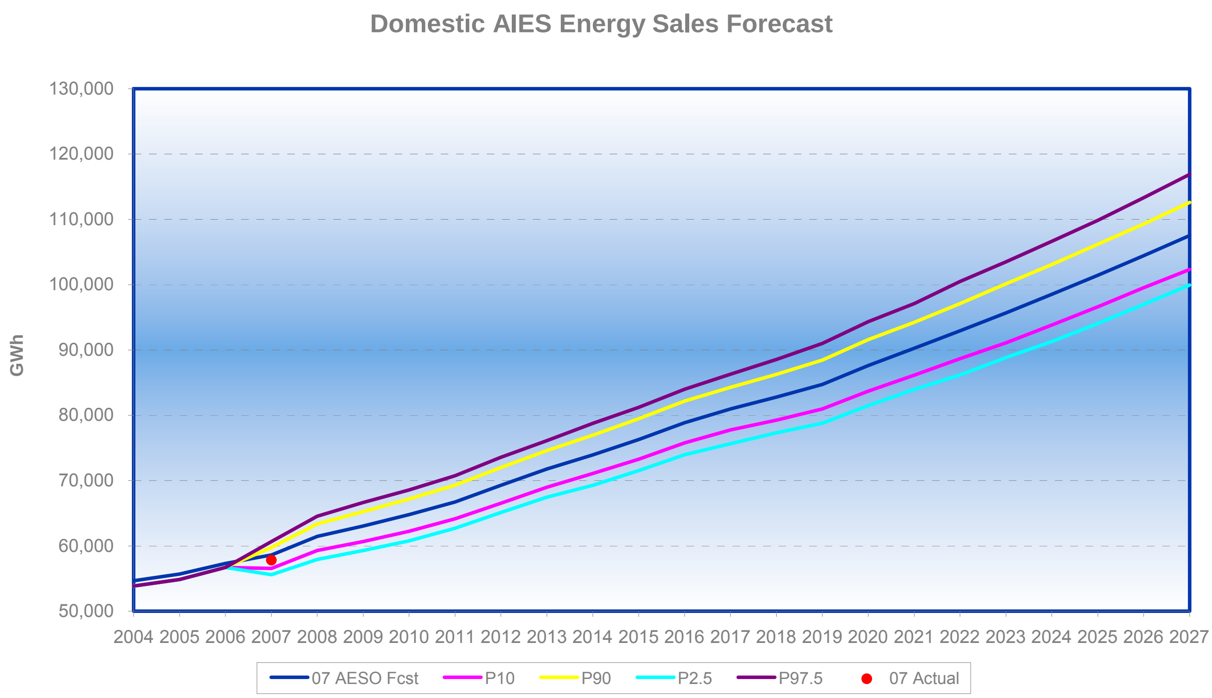


Figure 6 illustrates the domestic AIES energy sales forecast bands for the 80% and 95% confidence intervals together with the 07 Fcst results. Although the 07 Fcst has embedded in it a small adjustment in the farm energy forecast (as outlined in the Appendix), it does not materially affect the relative position of the 07 Fcst. Clearly, the 07 Fcst is still in the middle of the forecast bands. The actual domestic AIES energy consumption is plotted in Figure 6 as a single point (a red dot) and clearly shows that the actual 2007 energy is well within the calculated confidence bands and very close to the 07 Fcst, as would be expected. The difference between the historical data (denoted by the 07 Fcst between 2004 and 2006) and the P-values is due to the small discrepancies between the methodology and the actual data when comparing the Base Case to the 07 Fcst data, as outlined in the Appendix. The differences are mainly due to discrepancies in the calculation of historical losses.

Figure 6 also illustrates that the AIES energy forecast confidence intervals grow slightly over time in both absolute terms and percentage terms. The 80% confidence interval deviation from the base case forecast for the P10 and P90 starts in the +/- 2 to 3 percent range widening to around +/- 5 percent, while the 95% confidence intervals, represented by the P2.5 and P97.5 band, starts out in the +/- 4 to 5 percent range

[6] BTF includes City of Medicine Hat's load in the 07 Fcst.

widening to around +/- 8 percent by 2027. As outlined earlier in this Report, it is not known the degree to which these confidence interval forecasts would change if the specification and conditioning errors were also incorporated into the analysis. Further research and analysis would be required to address these additional sources of potential error.

Figure 7 shows the results for AIL energy in graphical form. Like in the AIES case, the 07 Fcst is positioned in the middle of the forecast bands. The 07 actual AIL energy, shown as a single point (red dot) in Figure 7, is well within the forecast bands and very close to the 07 Fcst.

Figure 7 - AIL Energy Confidence Intervals

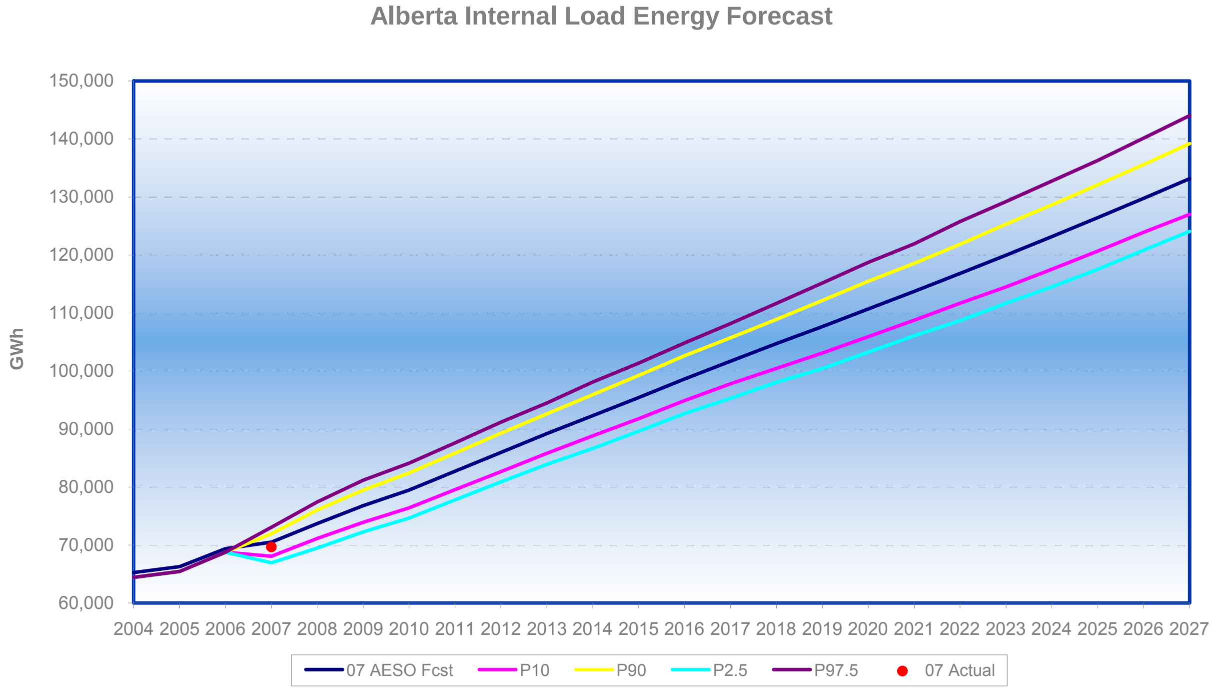


Figure 7 also illustrates that the AIL energy forecast confidence intervals grow slightly over time in both absolute terms and percentage terms. The 80% confidence interval deviation from the base case forecast for the P10 and P90 starts in the +/- 2 to 4 percent range widening to around +/- 4 to 5 percent, while the 95% confidence intervals, represented by the P2.5 and P97.5 band, starts out in the +/- 4 to 5 percent range widening to around +/- 7 to 8 percent by 2027.

Peak Demand Forecast Confidence Intervals

In the 07 Fcst, the AESO forecasts peak demand by allocating annual energy using historical load shapes for each metering point identifier (MPID), at each hour of the year for every year in the forecast horizon. The 07 Fcst load factors were calculated from AIES and AIL energy and demand, where the forecast confidence intervals could then be derived essentially using the same load factors of the 07 Fcst as a starting point. However, by employing this methodology, the peak demand forecast bounds would not include any variance for abnormal conditions that could affect the peak demand at any point in time.

There are two main factors that could affect the peak demand confidence interval forecast, weather and large industrial loads. Since demand is driven by very specific weather conditions at the time of system peak, which is typically short-term in nature, this would not be accounted for in the overall energy consumption interval forecast and therefore must be accounted for separately. Similarly, since Alberta electricity demand is dominated by large industrial loads, the operations of these facilities can also influence peak demand at any point in time. The impact to the system demand from significant changes to a large loads plant gate electrical demand, resulting from equipment mechanical failure or the unanticipated outage of an onsite generator, would tend to decrease or increase overall system demand—which again could be during a peak event.

Given the importance of the peak demand forecast in transmission and other system planning activities, an additional element of potential error was incorporated to the peak demand confidence interval analysis, to take into account the above noted conditions that can affect the peak demand forecast. This was done by incorporating the load factor variance seen over the last 8 years and adjusting it for factors that may offset the load factor error. The adjustment is made to avoid the assumption that, for example, the load factor will always be high when load growth is low, both of which would tend to depress the peak demand. In reality, a combination of factors could cause a low load factor (e.g. weather raising the peak demand), with low load growth (that would depress the peak) also a possible combination.

There is a notable difference between the weather variability in the energy forecast and the peak demand forecast. The load factor variance that is incorporated in the peak demand interval forecast is meant to capture, among other things, specific weather conditions on the day and time that the system peaks and affect the peak demand forecast exclusively. On the other hand, the energy forecast (that is also used to forecast the peak demand) implicitly assumes normal weather throughout the year and does not allow for any error in energy consumption due to abnormal weather conditions.

Incorporating the load factor variance uncertainty in the estimation of the peak demand confidence interval, recognizes that the peak demand forecast has an inherently higher variability (i.e. uncertainty) than the energy forecast. Finally, it should be noted that because the peak demand confidence intervals are being forecasted assuming "constant" load factors across the different P-values, the interval forecast ignores that there could be different customer category market shares and therefore a slightly different system load factors at different P-levels. Table 1 to Table 4 in the Appendix show the results for the P10, P90, P2.5 and P97.5 AIES and AIL peak demand forecast confidence intervals.

Figure 8 - AIES Peak Demand Confidence Intervals

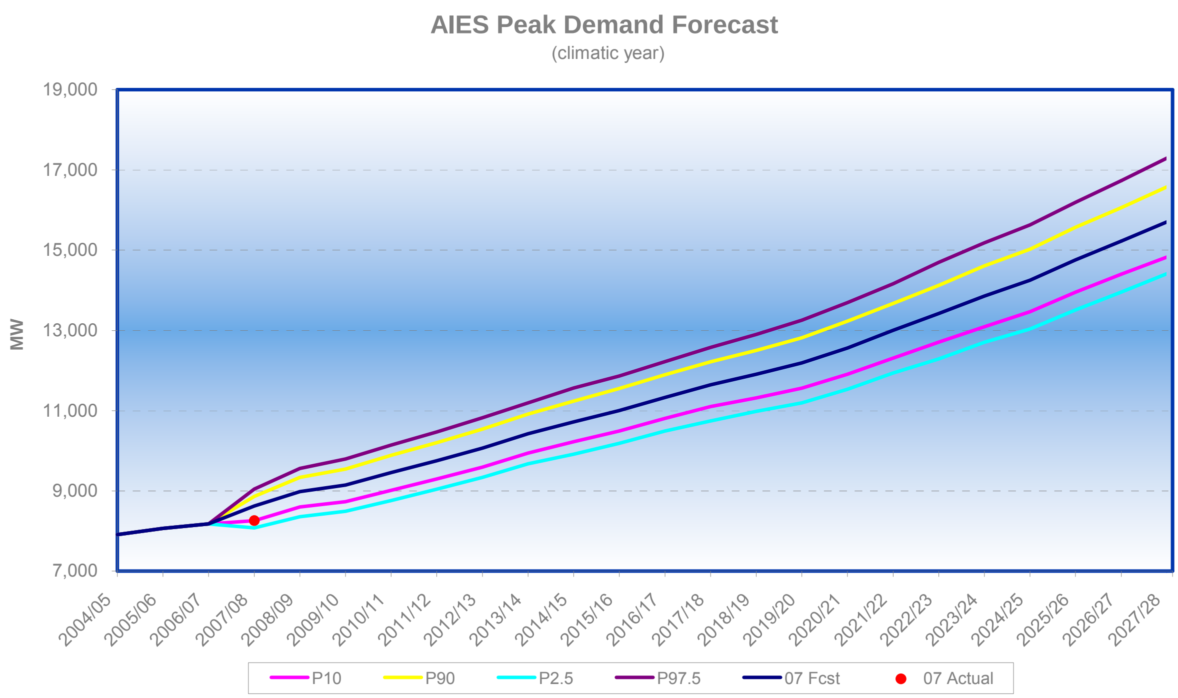
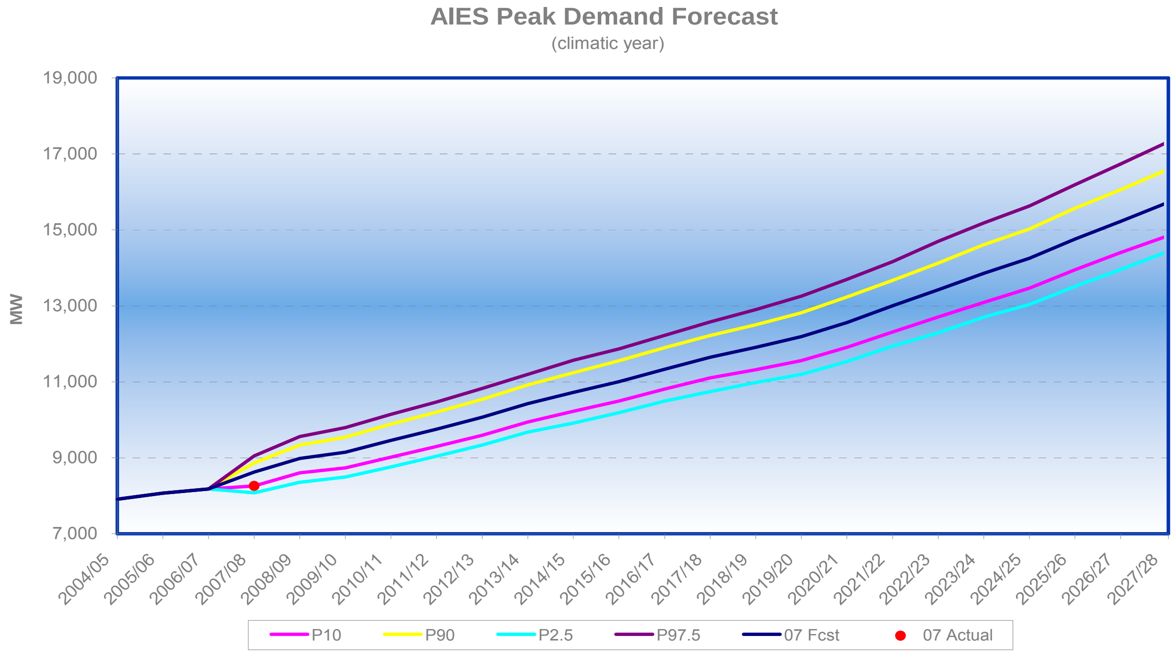


Figure 8 shows the results for the AIES peak demand confidence intervals in graphical form, together with the 07 Fcst and the actual peak for the 2007/08 winter (denoted by a red dot). Figure 9 shows the forecast confidence interval results for the AIL peak demand along with the 2007/08 actual AIL demand. Neither of the peak demand forecasts include any export sales. However, exports could occur at the time the system peaks increasing the amount of generation required in the province. In practice, exports are quite unlikely to occur due to the level of demand and the potential for very high pool prices, notwithstanding current transmission constraints associated with exports during high intra-Alberta demand.

Figure 8 also illustrates that the AIES peak demand forecast confidence intervals grow slightly over time in both absolute terms and percentage terms. The 80% confidence interval deviation from the base case forecast for the P10 and P90 starts in the +/- 3 to 4 percent range widening to around +/- 5 to 6 percent, while the 95% confidence intervals, represented by the P2.5 and P97.5 band, starts in the +/- 5 to 6 percent range and widens to around +/- 7 to 10 percent by 2027/28.

Figure 9 also illustrates that the AIL peak demand forecast confidence intervals grow slightly over time in both absolute terms and percentage terms. The 80% confidence interval deviation from the base case forecast for the P10 and P90 starts in the +/- 3 to 4 percent range, and widens to around +/- 5 to 6 percent at the end of the period. The 95% confidence intervals, represented by the P2.5 and P97.5 band, starts in the +/- 6 to 7 percent range and widens to around +/- 8 to 10 percent by2027/28.

Figure 9 - AIL Peak Demand Confidence Intervals



It should be noted that the 2007/08 actual AIES and AIL peak demand both lie very close to the P10 value, meaning that there was a 10% probability for the peak to be even lower, notwithstanding that the confidence interval bands ignore some potential sources of error. This result contrasts with the energy forecast results where the 2007/08 actual values were very close to the 07 Fcst. This is due to the fact that there were factors in the 2007/08 winter that affected the peak demand exclusively, which did not have a material affect on overall energy sales.

During most of recent history, the system peak demand in Alberta has occurred in early to mid December, with the presence of Christmas lighting, a shorter day light period and low ambient temperatures. However, in December of 2007 ambient temperatures were not low enough to cause the peak demand to reach its maximum at the same time that the Christmas lights were in full glow. By the time temperatures became very cold and the system peak occurred, Christmas lights were already off causing the AIL peak that occurred in January 2008 to only be 9 MW above the December 2007 peak. The colder weather in January that increased electrical load was offset by a reduction in the amount of Christmas decorative lighting.

In addition, the peak demand this past winter was further affected by the fact that operations at some large oil sands projects were disrupted due to operational problems, including a fire at a large upgrader. These heavy industrial facilities have a noticeable impact on demand due to their size.

These factors are the primary reason behind the slightly wider confidence intervals around the peak demand forecast as compared to the confidence intervals developed around the energy forecast. The inclusion of the load factor variance in the peak demand forecast confidence intervals is meant to capture some of the variability due to these kinds of influences.

Summary and Conclusions

This report presents 80% and 95% confidence interval forecasts for annual AIES and AIL energy and peak demand, based on the AESO's 07 Fcst from 2007 to 2027 (20 years). The scope of the study was based on utilizing the existing AESO forecast model design, methodologies and results. The Consultants did not have any direct input or involvement in the development of the AESO 07 Fcst. Any potential model specification errors and most conditioning errors in the 07 Fcst, have not been accounted for in the analysis of confidence intervals performed for this report.

The methodology and the estimated confidence bands by sector are believed to be applicable at the sub-regional level, for example if the AESO 07 Fcst is broken down into the north and south regions. However, the methodology and confidence bands cannot reasonably be applied at the level of an area forecast; rather, this should reflect the approach taken to developing the area forecast, which may be significantly different than the provincial or sub-regional level forecast.

The AESO 07 Fcst methodology of forecasting energy by customer category was used to produce the AIES and AIL energy and peak demand confidence interval forecasts. The 07 Fcst uses three basic forecast models to predict future electrical energy consumption: one model for the residential sector that utilizes an engineering model methodology; a second model for the farm sector that utilizes econometric techniques; and, a third model for commercial and industrial sectors combined, which encompasses behind the fence energy consumption and also utilizes econometric techniques. The third model has the greatest impact on the forecast, as energy in the commercial and industrial sector is forecast to represent 84% to 89% of total energy consumption over the forecast period, excluding losses.

As noted above, the commercial and industrial sectors as well as the farm sector energy sales are forecast according to econometric models, using ordinary least squares methods. The econometric models assume that energy consumption can be modeled as a linear function of a set of independent variables, plus a disturbance term. In the case of the commercial and industrial energy model, the explanatory variables are provincial GDP and a lagged energy consumption variable.

The confidence intervals for the econometric regression models were derived using an analytic method, which takes into account residual uncertainty and coefficient uncertainty in calculating the forecast errors and variances. However, this method does not take into account model specification and conditioning error. Specification error relates to the fact that, it may not be true that the assumptions of the econometric model are met including the functional form and the explanatory variables utilized in the econometric model such that no relevant variables are excluded. Conditioning error refers to the fact that the value of the explanatory variables on which the forecast is conditioned, may be inaccurate. This effectively means that when deriving the forecast confidence intervals with the analytic approach, it is assumed that the future values of the independent variables are either known with certainty or forecast without error.[7]

In this study the forecast confidence intervals were produced assuming that the specification error and the conditioning error are absent, while the sampling error and random error are present when forecasting farm, commercial and industrial sector energy consumption. By design, this also leads to the derivation of energy confidence bands based on normalized weather, since the analytic method does not allow for errors in the weather related independent variables used in the farm regression. Specifically, cooling-degree-days and heating-degree-days are assumed to be equal to the 21-year historical average throughout the forecast of the farm forecast confidence intervals. However, to some extent this has been compensated for in the derivation of demand confidence intervals with the introduction of a load factor variance.

The commercial and industrial sectors drive most of the provincial energy consumption, due to their overall size as compared to the other sectors. Therefore, the AIES and AIL energy and peak demand confidence intervals

[7] In the case of the 07 Fcst the GDP explanatory variable is a forecast from the Conference Board of Canada. It is unlikely for this forecast to be perfect and the variance of the GDP forecast should be incorporated in calculating the future potential variance of the energy consumption forecast. However, incorporating this error greatly complicates the computational requirements and most econometric authors view this as simply intractable. Some authors have proposed alternative methods like "bootstrapping" to produce confidence intervals when future-period values of exogenous variables are not known with certainty. However, this method also requires a considerable amount of time and effort.

primarily depend on the analytical approach used in calculating the forecast variance of this sector, which is based on traditional statistical methods. The method calculates the variance of the forecast that under certain conditions has a *t*-distribution that can then be used to derive the forecast bands.

The AIL and AIES energy confidence intervals produced in this study assume normal weather conditions and the absence of specification and conditioning errors in 87% or more of the forecast. The exception is the portion of the forecast that corresponds to residential sales, where most of the variance is due to the conditioning error in the input variables (population and customers as a percentage of population). The peak demand confidence intervals incorporate the variance implicit in the energy sales forecast intervals and also account for factors that affect the peak demand forecast exclusively, like weather and large load facility outages or loss of on-site generation at the time of system peak.

Given the assumptions and the limitations under which the analysis was completed, as outlined above, the confidence intervals presented in this report are considered to represent a reasonable band for the AESO 07 Fcst.

Appendix 1 – Accompaning Data File Notes

The Excel data file accompanying this report provides the detailed numerical results for the P10, P90, P2.5 and P97.5 values, some of which are also presented in this Appendix. The first tab “Base Case & AESO 07 Fcst” of the Excel data file compares the 07 Fcst results with the results presented in an AESO Excel spreadsheet named “Losses Summary File” and a “Base Case,” which was used as the platform from which the forecast confidence intervals were derived. The “Base Case & AESO 07 Fcst” tab also follows the methodology that the 07 Fcst uses in deriving the total AIES and AIL energy forecast, by aggregating energy by sector, then calculating retail sales to add transmission and distribution losses to later determine AIES and AIL energy.

The Base Case forecast was derived using the 07 Fcst methodologies without making any adjustments for actual data; this causes the 07 Fcst to be different from the Base Case in the 2004-2006 historical period. The discrepancies in the historical data seem to be due mainly to unexplained differences in the calculation of losses. For 2007 the Base Case differs from the 07 Fcst because the methodology does not yield the results reported in the 07 Fcst. After 2007 the Base Case and the 07 Fcst are almost identical, except for the fact that the 07 Fcst has an unexplained error in the farm forecast. The 07 Fcst includes a 64 GWh addition error to the farm forecast in 2007, and the effect of the error grows over time due to the dynamic nature of the forecast model. Although this error may be a concern within the farm forecast, it is not a particular concern over the entire AIES and AIL energy forecasts due to the small contribution of the farm sector to the total provincial forecast. Between 2008 and 2027 the only source of difference between the Base Case and the 07 Fcst is the error in the farm forecast, which amounts to 113 GWh in 2008 and grows to 173 GWh by 2027. This represents a discrepancy of less than 0.2% in the AIL energy forecast and the error declines over time in percentage terms.

The 07 Fcst has an adjustment in the Commercial and Industrial energy sector of -1,950 GWh in 2007 “to adjust for year-to-date changes seen in behind-the-fence (BTF) load from the previous year” and the effect of this trickles to the end of the forecast although the effect also declines over time. However, this is not a cause of any discrepancy between the Base Case and the 07 Fcst, because the adjustment is not an error in the 07Fcst and was simply incorporated in the Base Case, as well.

Therefore, after accounting for the error in the farm sector forecast, the methodology of the Base Case produces the same AIES and AIL energy that is reported in the 07 Fcst for the 2008 to 2027 period. Consequently, the forecast methodology was then employed to derive the forecast confidence intervals.

Table 1 to Table 4 below, as well as the associated Excel data file, show the results for the energy forecast confidence interval bands. P10 and P90 represent the bounds for the 80% confidence interval, while P2.5 and P97.5 represent the boundaries of the 95% confidence interval.

Table 1 to Table 4 illustrates the steps that were taken in obtaining AIES energy and AIL energy consumption. The results from the residential, farm, commercial and industrial energy sales at the different P-levels are aggregated to determine total energy consumption excluding any system losses. To that result BTF load is deducted to determine total retail energy sales. Because BTF load is forecast together with industrial and commercial energy sales in the AESO’s 07 Fcst, there is nothing fundamentally determining the BTF load forecast, in particular. Therefore in deriving the forecast confidence intervals, the BTF load’s share in the industrial and commercial sector was kept constant and equal to the 07 Fcst percentages.

Distribution wires energy losses are calculated as a percentage of total retail sales, to derive total distribution energy (denoted as DEM) in

Table 1 to Table 4. Similarly, transmission losses are calculated as a percentage of total DEM energy. The assumed transmission and distribution losses percentages are equal to the percentages used in the original 07 Fcst. Regarding transmission losses, the 07 Fcst incorporates an adjustment that would reduce losses resulting from expected transmission system upgrades starting in 2010. This adjustment is related to the potential North-South transmission upgrades to be built between Edmonton and Calgary. Correspondingly, the confidence interval forecast maintains the assumption of the 07 Fcst, which implicitly assumes no further delays or changes to the schedule and scope of the transmission upgrades.[8]

[8] A possible way of addressing the issue of the timing of any transmission upgrade of this magnitude would be to assign a probability with respect to the timing of the transmission project, and simulate the forecast using a Monte Carlo process. However, since most of the confidence interval forecasts rely on statistical methods that do not lend themselves to Monte Carlo techniques, the 07 Fcst assumption on transmission losses was maintained throughout the confidence interval forecast process.

Appendix 2 – Data Tables

Table 1 - P10 Energy and Peak Demand Results

														Climactic Year	
GWh	Residential	Farm	Comm & Industrial	Total Energy Excluding Losses	BTF % of Comm & Industrial	BTF	Retail Sales	Distribution Losses	DEM Load	Transmission Losses	AIES Energy	AIL Energy	Climatic Year	AIES Peak Demand MW	AIL Peak Demand MW
2004	7,374	1,732	50,149	59,254	21.1%	10,591	48,663	5.0%	51,093	5.4%	53,842	64,433	2004/05	7,910	9,236
2005	7,576	1,702	51,138	60,416	20.7%	10,571	49,846	4.4%	52,063	5.4%	54,865	65,435	2005/06	8,066	9,580
2006	8,044	1,766	53,443	63,253	22.6%	12,054	51,198	5.2%	53,874	5.3%	56,715	68,770	2006/07	8,177	9,661
2007	8,003	1,741	52,390	62,135	22.0%	11,545	50,590	6.3%	53,796	5.1%	56,539	68,083	2007/08	8,256	9,572
2008	8,171	1,758	54,842	64,770	21.6%	11,831	52,939	6.3%	56,295	5.3%	59,293	71,124	2008/09	8,599	9,981
2009	8,318	1,775	57,423	67,516	23.1%	13,255	54,262	6.3%	57,701	5.1%	60,662	73,916	2009/10	8,734	10,267
2010	8,450	1,790	60,084	70,324	23.6%	14,186	56,138	6.3%	59,697	4.2%	62,226	76,412	2010/11	9,015	10,652
2011	8,623	1,804	62,821	73,248	24.5%	15,406	57,842	6.3%	61,509	4.3%	64,135	79,541	2011/12	9,298	11,083
2012	8,721	1,816	65,569	76,107	24.6%	16,123	59,984	6.3%	63,786	4.3%	66,537	82,660	2012/13	9,593	11,461
2013	8,876	1,828	68,286	78,989	24.6%	16,820	62,170	6.3%	66,110	4.3%	68,984	85,804	2013/14	9,941	11,901
2014	9,031	1,839	70,908	81,779	25.0%	17,747	64,032	6.3%	68,090	4.4%	71,069	88,816	2014/15	10,224	12,294
2015	9,139	1,851	73,508	84,497	25.2%	18,495	66,001	6.3%	70,185	4.4%	73,273	91,769	2015/16	10,491	12,654
2016	9,307	1,861	76,197	87,366	25.1%	19,129	68,236	6.3%	72,562	4.4%	75,775	94,905	2016/17	10,805	13,040
2017	9,418	1,872	78,759	90,049	25.5%	20,057	69,992	6.3%	74,428	4.5%	77,748	97,805	2017/18	11,100	13,453
2018	9,403	1,883	81,236	92,523	26.1%	21,175	71,348	6.3%	75,871	4.5%	79,268	100,443	2018/19	11,318	13,811
2019	9,477	1,894	83,611	94,982	26.4%	22,106	72,876	6.3%	77,495	4.5%	80,979	103,085	2019/20	11,560	14,170
2020	9,629	1,905	86,016	97,550	25.9%	22,253	75,297	6.3%	80,070	4.5%	83,686	105,939	2020/21	11,906	14,525
2021	9,736	1,916	88,460	100,113	25.6%	22,629	77,485	6.3%	82,396	4.5%	86,138	108,767	2021/22	12,312	14,983
2022	9,891	1,927	90,950	102,768	25.3%	23,014	79,755	6.3%	84,810	4.6%	88,682	111,696	2022/23	12,709	15,423
2023	9,861	1,938	93,491	105,291	25.0%	23,391	81,900	6.3%	87,091	4.6%	91,092	114,482	2023/24	13,090	15,850
2024	10,039	1,950	96,089	108,077	24.7%	23,747	84,330	6.3%	89,675	4.6%	93,811	117,559	2024/25	13,466	16,262
2025	10,189	1,961	98,747	110,897	24.4%	24,051	86,846	6.3%	92,351	4.6%	96,627	120,678	2025/26	13,948	16,786
2026	10,406	1,973	101,470	113,849	24.0%	24,398	89,451	6.3%	95,121	4.6%	99,541	123,939	2026/27	14,400	17,278
2027	10,387	1,984	104,261	116,632	23.7%	24,708	91,924	6.3%	97,750	4.7%	102,309	127,017	2027/28	14,830	17,744

Table 2 - P90 Energy and Peak Demand Results

														Climactic Year	
GWh	Residential	Farm	Comm & Industrial	Total Energy Excluding Losses	BTF % of Comm & Industrial	BTF	Retail Sales	Distribution Losses	DEM Load	Transmission Losses	AIES Energy	AIL Energy	Climatic Year	AIES Peak Demand MW	AIL Peak Demand MW
2004	7,374	1,732	50,149	59,254	21.1%	10,591	48,663	5.0%	51,093	5.4%	53,842	64,433	2004/05	7,910	9,236
2005	7,576	1,702	51,138	60,416	20.7%	10,571	49,846	4.4%	52,063	5.4%	54,865	65,435	2005/06	8,066	9,580
2006	8,044	1,766	53,443	63,253	22.6%	12,054	51,198	5.2%	53,874	5.3%	56,715	68,770	2006/07	8,177	9,661
2007	8,485	1,865	55,300	65,649	22.0%	12,186	53,464	6.3%	56,852	5.1%	59,751	71,936	2007/08	8,861	10,359
2008	8,742	1,902	58,590	69,233	21.6%	12,640	56,593	6.3%	60,181	5.3%	63,386	76,026	2008/09	9,337	10,929
2009	9,065	1,926	61,612	72,602	23.1%	14,222	58,380	6.3%	62,080	5.1%	65,266	79,488	2009/10	9,542	11,306
2010	9,373	1,944	64,537	75,855	23.6%	15,237	60,617	6.3%	64,460	4.2%	67,192	82,429	2010/11	9,886	11,768
2011	9,649	1,960	67,446	79,055	24.5%	16,540	62,515	6.3%	66,478	4.3%	69,316	85,856	2011/12	10,205	12,251
2012	9,905	1,975	70,315	82,195	24.6%	17,290	64,905	6.3%	69,019	4.3%	71,995	89,285	2012/13	10,541	12,677
2013	10,105	1,988	73,139	85,232	24.6%	18,015	67,217	6.3%	71,477	4.3%	74,585	92,600	2013/14	10,915	13,151
2014	10,421	2,002	75,898	88,320	25.0%	18,996	69,325	6.3%	73,718	4.4%	76,943	95,939	2014/15	11,240	13,598
2015	10,714	2,015	78,648	91,377	25.2%	19,789	71,588	6.3%	76,125	4.4%	79,475	99,264	2015/16	11,554	14,014
2016	10,976	2,028	81,453	94,457	25.1%	20,449	74,008	6.3%	78,699	4.4%	82,185	102,634	2016/17	11,899	14,438
2017	11,073	2,041	84,223	97,336	25.5%	21,449	75,887	6.3%	80,697	4.5%	84,296	105,745	2017/18	12,219	14,890
2018	11,280	2,054	86,969	100,303	26.1%	22,669	77,634	6.3%	82,555	4.5%	86,252	108,921	2018/19	12,503	15,332
2019	11,549	2,067	89,682	103,298	26.4%	23,711	79,587	6.3%	84,630	4.5%	88,436	112,147	2019/20	12,818	15,782
2020	11,832	2,080	92,393	106,305	25.9%	23,903	82,403	6.3%	87,625	4.5%	91,583	115,486	2020/21	13,229	16,210
2021	11,882	2,094	95,116	109,092	25.6%	24,331	84,761	6.3%	90,133	4.5%	94,227	118,558	2021/22	13,675	16,720
2022	12,107	2,108	97,863	112,077	25.3%	24,763	87,314	6.3%	92,848	4.6%	97,088	121,850	2022/23	14,127	17,227
2023	12,436	2,121	100,644	115,201	25.0%	25,180	90,021	6.3%	95,727	4.6%	100,124	125,304	2023/24	14,610	17,764
2024	12,622	2,135	103,467	118,225	24.7%	25,571	92,654	6.3%	98,527	4.6%	103,071	128,642	2024/25	15,024	18,222
2025	12,871	2,149	106,341	121,361	24.4%	25,900	95,461	6.3%	101,511	4.6%	106,212	132,112	2025/26	15,569	18,818
2026	13,057	2,164	109,271	124,492	24.0%	26,273	98,219	6.3%	104,444	4.6%	109,298	135,571	2026/27	16,058	19,355
2027	13,347	2,179	112,262	127,788	23.7%	26,605	101,183	6.3%	107,597	4.7%	112,614	139,219	2027/28	16,578	19,919

Table 3 - P2.5 Energy and Peak Demand Results

															Climactic Year	
GWh	Residential	Farm	Comm & Industrial	Total Energy Excluding Losses	BTF % of Comm & Industrial	BTF	Retail Sales	Distribution Losses	DEM Load	Transmission Losses	AIES Energy	AIL Energy		Climatic Year	AIES Peak Demand MW	AIL Peak Demand MW
2004	7,374	1,732	50,149	59,254	21.1%	10,591	48,663	5.0%	51,093	5.4%	53,842	64,433		2004/05	7,910	9,236
2005	7,576	1,702	51,138	60,416	20.7%	10,571	49,846	4.4%	52,063	5.4%	54,865	65,435		2005/06	8,066	9,580
2006	8,044	1,766	53,443	63,253	22.6%	12,054	51,198	5.2%	53,874	5.3%	56,715	68,770		2006/07	8,177	9,661
2007	7,879	1,706	51,525	61,110	22.0%	11,354	49,756	6.3%	52,909	5.1%	55,607	66,960		2007/08	8,078	9,339
2008	7,840	1,717	53,727	63,284	21.6%	11,591	51,693	6.3%	54,970	5.3%	57,897	69,488		2008/09	8,354	9,675
2009	8,090	1,732	56,177	65,999	23.1%	12,967	53,032	6.3%	56,393	5.1%	59,287	72,255		2009/10	8,493	9,958
2010	8,193	1,746	58,759	68,698	23.6%	13,873	54,825	6.3%	58,300	4.2%	60,771	74,644		2010/11	8,759	10,324
2011	8,411	1,759	61,445	71,616	24.5%	15,068	56,547	6.3%	60,132	4.3%	62,699	77,768		2011/12	9,043	10,751
2012	8,538	1,771	64,158	74,467	24.6%	15,776	58,691	6.3%	62,411	4.3%	65,102	80,878		2012/13	9,338	11,126
2013	8,648	1,782	66,842	77,272	24.6%	16,464	60,808	6.3%	64,662	4.3%	67,473	83,938		2013/14	9,674	11,551
2014	8,582	1,793	69,424	79,799	25.0%	17,375	62,424	6.3%	66,380	4.4%	69,284	86,659		2014/15	9,917	11,903
2015	8,737	1,804	71,979	82,520	25.2%	18,111	64,409	6.3%	68,492	4.4%	71,506	89,617		2015/16	10,186	12,261
2016	8,879	1,814	74,634	85,327	25.1%	18,737	66,590	6.3%	70,811	4.4%	73,947	92,684		2016/17	10,491	12,636
2017	8,775	1,824	77,134	87,732	25.5%	19,643	68,089	6.3%	72,405	4.5%	75,634	95,278		2017/18	10,744	13,004
2018	8,941	1,834	79,531	90,307	26.1%	20,730	69,577	6.3%	73,987	4.5%	77,300	98,031		2018/19	10,981	13,375
2019	8,892	1,845	81,805	92,542	26.4%	21,628	70,914	6.3%	75,408	4.5%	78,799	100,427		2019/20	11,192	13,698
2020	9,101	1,855	84,120	95,076	25.9%	21,762	73,314	6.3%	77,960	4.5%	81,482	103,244		2020/21	11,534	14,046
2021	9,294	1,865	86,481	97,641	25.6%	22,122	75,518	6.3%	80,305	4.5%	83,952	106,075		2021/22	11,939	14,499
2022	9,223	1,876	88,894	99,994	25.3%	22,493	77,500	6.3%	82,412	4.6%	86,175	108,668		2022/23	12,287	14,889
2023	9,479	1,886	91,364	102,730	25.0%	22,858	79,872	6.3%	84,934	4.6%	88,835	111,694		2023/24	12,701	15,344
2024	9,470	1,897	93,895	105,262	24.7%	23,205	82,057	6.3%	87,258	4.6%	91,283	114,487		2024/25	13,037	15,713
2025	9,648	1,907	96,489	108,044	24.4%	23,501	84,543	6.3%	89,902	4.6%	94,065	117,566		2025/26	13,509	16,225
2026	9,917	1,918	99,150	110,985	24.0%	23,840	87,145	6.3%	92,669	4.6%	96,975	120,815		2026/27	13,958	16,710
2027	10,123	1,929	101,881	113,933	23.7%	24,144	89,789	6.3%	95,480	4.7%	99,932	124,076		2027/28	14,412	17,197

Table 4 - P97.5 Energy and Peak Demand Results

														Climactic Year	
GWh	Residential	Farm	Comm & Industrial	Total Energy Excluding Losses	BTF % of Comm & Industrial	BTF	Retail Sales	Distribution Losses	DEM Load	Transmission Losses	AIES Energy	AIL Energy	Climatic Year	AIES Peak Demand MW	AIL Peak Demand MW
2004	7,374	1,732	50,149	59,254	21.1%	10,591	48,663	5.0%	51,093	5.4%	53,842	64,433	2004/05	7,910	9,236
2005	7,576	1,702	51,138	60,416	20.7%	10,571	49,846	4.4%	52,063	5.4%	54,865	65,435	2005/06	8,066	9,580
2006	8,044	1,766	53,443	63,253	22.6%	12,054	51,198	5.2%	53,874	5.3%	56,715	68,770	2006/07	8,177	9,661
2007	8,601	1,900	56,166	66,667	22.0%	12,376	54,290	6.3%	57,731	5.1%	60,674	73,051	2007/08	9,046	10,606
2008	8,874	1,943	59,704	70,522	21.6%	12,880	57,641	6.3%	61,295	5.3%	64,560	77,440	2008/09	9,560	11,224
2009	9,307	1,969	62,857	74,133	23.1%	14,509	59,624	6.3%	63,403	5.1%	66,657	81,166	2009/10	9,796	11,638
2010	9,565	1,988	65,862	77,415	23.6%	15,550	61,865	6.3%	65,787	4.2%	68,575	84,125	2010/11	10,143	12,108
2011	9,861	2,005	68,821	80,687	24.5%	16,877	63,810	6.3%	67,855	4.3%	70,752	87,629	2011/12	10,471	12,606
2012	10,193	2,020	71,726	83,939	24.6%	17,637	66,302	6.3%	70,505	4.3%	73,545	91,182	2012/13	10,825	13,052
2013	10,344	2,034	74,582	86,960	24.6%	18,371	68,590	6.3%	72,937	4.3%	76,108	94,479	2013/14	11,196	13,527
2014	10,898	2,048	77,382	90,328	25.0%	19,367	70,961	6.3%	75,458	4.4%	78,759	98,126	2014/15	11,566	14,021
2015	11,080	2,062	80,177	93,318	25.2%	20,173	73,145	6.3%	77,780	4.4%	81,203	101,377	2015/16	11,867	14,427
2016	11,382	2,075	83,016	96,473	25.1%	20,841	75,632	6.3%	80,426	4.4%	83,988	104,829	2016/17	12,223	14,865
2017	11,625	2,089	85,848	99,561	25.5%	21,863	77,699	6.3%	82,623	4.5%	86,309	108,171	2017/18	12,576	15,355
2018	12,030	2,103	88,674	102,806	26.1%	23,113	79,693	6.3%	84,744	4.5%	88,539	111,652	2018/19	12,901	15,843
2019	12,455	2,117	91,488	106,059	26.4%	24,188	81,871	6.3%	87,059	4.5%	90,974	115,162	2019/20	13,254	16,337
2020	12,844	2,130	94,289	109,263	25.9%	24,393	84,870	6.3%	90,249	4.5%	94,325	118,719	2020/21	13,696	16,798
2021	12,925	2,145	97,095	112,164	25.6%	24,837	87,327	6.3%	92,862	4.5%	97,080	121,917	2021/22	14,162	17,332
2022	13,576	2,159	99,918	115,654	25.3%	25,283	90,371	6.3%	96,099	4.6%	100,486	125,769	2022/23	14,698	17,925
2023	13,825	2,174	102,771	118,770	25.0%	25,712	93,058	6.3%	98,956	4.6%	103,501	129,213	2023/24	15,181	18,466
2024	14,127	2,188	105,662	121,977	24.7%	26,113	95,864	6.3%	101,940	4.6%	106,642	132,755	2024/25	15,626	18,957
2025	14,395	2,203	108,599	125,197	24.4%	26,450	98,747	6.3%	105,006	4.6%	109,868	136,319	2025/26	16,189	19,575
2026	14,846	2,219	111,591	128,656	24.0%	26,831	101,825	6.3%	108,279	4.6%	113,311	140,142	2026/27	16,734	20,170
2027	15,312	2,234	114,642	132,188	23.7%	27,169	105,020	6.3%	111,676	4.7%	116,884	144,052	2027/28	17,297	20,779