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Distribution Transformer Load Management

1 Introduction

A computer model of residential consumers demand has been developed that enables close estimation of the load at the feeding distribution transformer. Outputs of the model include true (3-phase) maximum demand estimation, transformer top oil temperature and winding hot spot temperature, rate of loss of transformer insulation life and demand estimation of the transformer bushings phase currents. Transformer loss, including loss at time of system peak, may also be estimated.

The model has been tested and shows excellent agreement to measured maximum demand records. The method provides better management of a utilities distribution transformers than conventional monitoring using Maximum Demand Instruments (MDIs) or thermal strips, and at a substantially lower cost.

2 Managing Distribution Transformer Demand

Residential demand modeling using computer simulation is a viable alternative for managing distribution transformer loading.

Hyland McQueen Limited have developed and tested a model and supporting software providing the ability to closely estimate the demand-duration profiles of a group of residential customers based on their energy consumption. The accuracy of the modeling method is demonstrated by the close agreement between the empirical (data) and model curves in the chart following (figure 1). This chart shows the demand (in kW) on the x-axis versus the duration quantile on the y-axis (i.e. the portion of time the load was equal to or less than).

Key points about the modeling process are:

1. It is a statistical model. It does not predict the exact demand at any particular time but over a sufficiently long period (ie a year) it closely reproduces the demand-duration that would occur.
2. The model is applied to residential customers; commercial and industrial customers are included by using historic half-hourly metering records where available or they correspond to a proxy “type” for which a load behaviour is assigned from base data sets. This is because industrial and commercial consumers often represent large single loads with high demands expressed in unique patterns that cannot be treated

suficiently with statistical methods.

3. Although the modeling method incorporates “Monte Carlo” simulation to reproduce the mean and dispersion of demand, the way this is implemented is substantially different to commercial programs such as “@Risk”. These programs are ineffective tools for this modeling problem, which requires dynamic distributional shape estimation. Hyland McQueen have developed specific programs for this task.
4. The method <u>does not</u> require customer profile information. Additionally, not every customer’s energy bill is required, although clearly the more that are available the better the final result.
5. The method is proven robust for residential consumers from across New Zealand (Auckland to Dunedin).
6. The method has been verified by comparison of the predicted maximum demands from the model to measured maximum demands from field recorders. This shows our models produce reasonable matches to the demand-duration profiles even up to the 99.99 percentile.

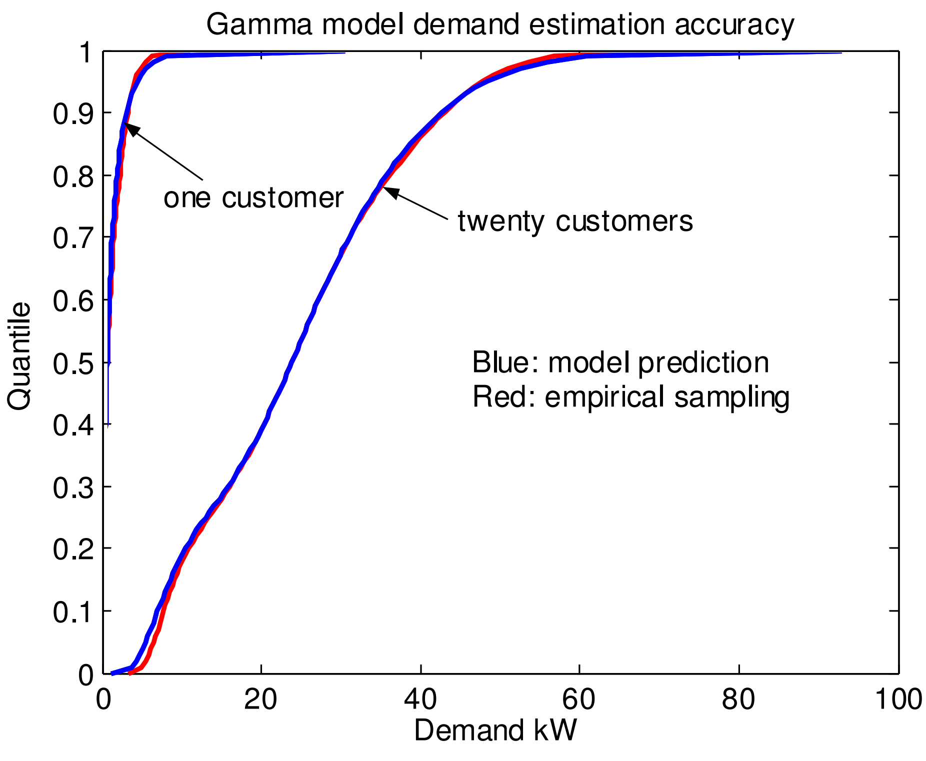

Figure – 1. Demand model vs measured data.

3 Maximum demand recorders are not effective in managing distribution transformer load.

The limitations of maximum demand recorders as a tool for managing distribution transformers are well known within the utility industry. Problems include:

- Both weather conditions and load co-incidence drive maximum demand. Our research indicates the greatest influence is load co-incidence. By managing to a recorded maximum demand, the utility is essentially managing to a one-off random event without knowledge of the actual demand-duration.

- Maximum demand recorders are commonly installed on individual phases, then the phase maximums added together. Because individual phase maximums do not occur at the same time, the indicated maximum demand from the summed phases overstates the true (3-phase) demand. The extent of the over-estimation depends on the number of consumers connected to the transformer. For a transformer with 25 consumers, the indicated maximum demand (over one year) will be approximately 15% greater than the true maximum demand.
- Reading and maintaining maximum demand recorders is expensive. Reading and maintenance costs would typically average $15 per instrument per year.
- Field reading maximum demand indicators introduces data errors that are difficult or impossible to identify later.

In view of the problems with maximum demand recorders, many utilities have either abandoned the load management of their distribution transformers, manage through simple monitoring of the customer numbers connected to each transformer, or install and read maximum temperature recording strips affixed on the transformer tank.

Abandoning load management completely, carries a significant risk of overloading transformers as load conditions change. Many utilities have found this to their cost.

If a utility abandons completely the measurement or estimation of transformer demand, then the general experience is nothing happens for some years. Then the utility finds itself with substantial problems of failing transformers. This is due to combinations of:

- Organic load growth
- In-fill housing
- Changes in consumer groupings (ie older areas becoming more fashionable with a gradual change in consumer type; young families taking over older neighbourhoods etc.).

While simple monitoring of the number of consumers connected to transformers is a useful “rule of thumb”, the substantial differences in demand behaviour between different groupings of customers make this method crude at best.

Annual reading of maximum temperature strips provides a better indication of transformer stress but has significant limitations.

Affixing maximum reading thermal strips to the transformer tanks is often considered a better guide to transformer load. This may be so if compared just to maximum demand recorders, but significant problems remain. These are:

- It is still a single point-in-year measurement of an upper-end random event.
- The transformers must be visited each year to read the strips and replace them.

- The temperature strips measure the top oil temperature but the temperature of significance to the transformer is the winding hot spot temperature. This temperature cannot be estimated from the top oil temperature due to the different thermal time constants involved and the spiky nature of the load changes.
- Temperature is only part of the story. Managing transformer load must also consider the transformer bushings ratings, being typically 150% of the transformer rating. Both temperature and maximum demand are needed.
- Thermal strips are encumbered with reading problems on overhead transformers and with UV deterioration of the strips.

Computer modeling is the best alternative because it is cheap, sufficiently accurate, and looks at the loading over the whole year – not just one half hour in the year. Because the load is modelled in each half-hour of the year, we are able to apply thermal models as per standard CP1010 or AS2374 part 7. This enables consideration of the stress on the transformer integrated over the whole year as well as expected yearly maximums.

In addition, establishing and using a model enables "what-if" analysis for such things as extreme weather, assessing consumer load change behaviour, tariff switching, impact of hot water control methods, fuel switching, etc.

4 Roll-out of Smart Meters

A question often asked is "won't the roll-out of smart metering make this redundant?". The answer is no for a combination of reasons:

1. Roll-out will take a number of years to complete; the ability to mix the specific half-hourly load data from smart meters with cumulative total billing data is a strength of the method.
2. Data from smart meters can be used to improve the customer models and identify specific customer characteristics.
3. An important point often missed is that a years physical data for a customer may not represent typical behaviour for that customer. The fact that measured maximum demand on a distribution transformer often varies significantly from year-to-year is testimony to this. A strength of the method proposed is the ability to identify the range of typical maximum demand behaviour in any year so that transformer load is not managed in an ad-hoc manner.

5 Process

The process for demand modelling has the following steps.

Information Requirements

- List of transformers and their kVA ratings.
- Energy billing records for the customers linked to those transformers (ie customer *No abc* is connected to transformer *No xyz* and their winter energy bill was 4,632kWh for a

120 day period. (Note that not all billing records are required, however >70% is desirable)

- Half hourly demand data over the customer billing period for a feeder or zone substation or grid exit point, servicing mostly residential customers.
- Daily temperature records over the customer-billing period (we generally source these ourselves from crown agencies).
- Description of hot water control and/or tariff switching undertaken.
- If available, transformer age, rating etc. for estimating the transformer characteristics including load and no-load loss.

Analysis

Given the appropriate consumer and transformer information, the process is:

- Pre-check the information for anomalies and data errors.
- Place the provided information into our specifically designed database
- Run the demand models.
- Compile the results and rank the transformers.
- Document the outcomes.

Outputs

The basic output of the process is:

- Listing of transformers ranked on the calculated loss of insulation life (years per year)
- Expected phase current maximums at the 99.9 and 99.99 percentiles
- Top oil temperature at the 99.9 and 99.99 percentiles (calculated as per CP1010 or AS2374)
- Winding hot spot temperature at the 99.9 and 99.99 percentiles (calculated as per CP1010 or AS2374)
- Transformers exceeding pre-determined loading criteria are highlighted: Criteria generally includes:

  Rate of loss of insulation life >= 1 year per year
  Hot spot temperature >= 140°C at the 99.9 percentile
  Any phase current maximum >= 150% of transformer rating at the 99.9 percentile

- Identification of the distribution transformer contribution to network energy losses and loss at time of peak as well as an overall measure of the efficiency of the transformer loading practices.

Additional outputs may include:

- Assessment of the impact of load control and/or night rate tariff switching.
- What-if analysis on the impact of changes in demand patterns or average load levels (eg electricity to gas fuel switching).
- Review of network design policies (appropriate ADMD per customer etc).

- Risk estimation on the effect of extreme weather events.

6 Conclusion

The described method for modelling transformer load provides an effective tool for the management of distribution transformer assets and provides a better understanding of the efficiency and prudence of the transformer loading practices employed.

7 More Information

For more information and/or a quote on costs, please contact:

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