

The Load Management Functions that must be delivered by the Smart Metering System

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Abstract

Great-Britain's unique Radio Teleswitch System (RTS) was developed in the 1970s, deployed en-masse by the Electricity Industry during the 80s and 90s. Today it controls electric storage and water-heating in homes numbering in the low millions. The need for its development mirrors the conditions of the near future, where much generating plant capacity will close and there will be a great expansion of electric heating in the form of heat-pumps. The system allowed this expansion to occur while limiting its economic impact on generation, transmission and distribution networks. This is as relevant today as it was in the past and provides functionality that the Smart Metering System (SMS) must duplicate, or else trigger network investments and higher costs for consumers.

1 Introduction

The Radio Teleswitch System (RTS) was the 1970s era answer to the problem of Load Management. Since then it has been used to control the electrical load drawn by millions of storage heaters, often in rural or remote areas of Great Britain. The system is unique and due to be superseded by the Smart Metering System. The experience of using the RTS in the Scottish Hydro Electric Power Distribution (SHEPD) Licence Area and its key functions have been collated in this paper to provide a source of reference and information. The SMS is now being designed and it is important for the security of electricity supply, that this successor Load Management system has the necessary functionality to replace the RTS that is in-place today.

This paper begins with a review of the history and development of the RTS, presents the system itself and assesses the value of the present-day Load Management that it effects.

The key functionality that the successor system should implement to maximise Load Management value and minimise the cost of operating rural and remote electricity networks will be presented.

2 History and Development of the Radio Teleswitch System

The system was developed during the 1970s in response to a growing night-time peak in demand due to the proliferation of the newly developed electric storage-heater coupled with the forerunner of the Economy 7 (E7) tariff, the 'White Meter'. The White Meter tariff was delivered using mechanical time-switches and a two-rate meter ('normal' and 'low') that were installed in customers' premises. The 'low' rate lasted 8 hours. The aim behind the tariff was to reduce the overall cost of generating electricity for electric heating, by shifting demand to the night, lengthening the scheduled run-times of generators and reducing overall generation capacity.

The scheme was so successful that it altered the national load profile, creating the danger of a new night-time peak. The, then, Central Electricity Generating Board (CEGB) was charged by statute with delivering the cheapest possible electricity; which conflicted with the expensive and wasteful manner in which the demand-peak would be met. The Energy Management Task Force was formed to address the challenge, identifying the aims of the concept originally known as "Load Management" and today as "Smart Metering" and "Demand-Side Management":

- Two-way communications to each customer;
- Tariff information sent to the customer;
- * Load control for customer heating and cooling;
- * Flexible tariff rates, up to half-hourly or spot-pricing;
- Return of meter readings;
- * Fraud prevention; and
- Remote connection and disconnection for non-payment, tenancy changes or ownership changes.

The research department of the BBC had developed and implemented radio data transmission for VHF and FM; similar ideas existed for LW transmission. The Electricity Supply Industry funded the development of the LW Radio Data system, to transmit the messages necessary to control what was regarded as the best solution to the Load Management problem; the Radio Teleswitch System. The system (addressing the features marked * in the list above) facilitated the use of a centralised hub with the facility to change both the tariff-switching times held in the new Teleswitches on customers' premises and to independently

switch-on or off the connected water-heating and storage-heating loads.

3 System Composition and Specification

The system comprised:

- Teleswitches (approximately 3 million) in customer premises (see Figure 1);
- A radio transmission network of three LW transmitters; Droitwich (400kW, 213m aerial system); Westerglen (50kW, 150m); Burghead (50kW, 150m);
- The BBC Message-Assembler at Crystal Palace;
- The Central Teleswitching Control Unit (CTCU) that; provides the facility for network operating companies to update switching times; keeps a model of the operating times of all Teleswitches and ensures that broadcasts are made at the correct times to keep the stored programmes up-to-date;
- Network operating companies' terminal equipment that interfaces to the CTCU; and
- Broadcast-monitors that interface to the CTCU to determine if broadcasts have been received and trigger re-transmission if not.

The system was designed to prevent fraud by virtue of the delivery of switching programmes in advance of switching times. Sending of switch-on and switch-off instructions would have made the device susceptible to fraud by shielding of the receiver once it had been switched-on. The system was designed with the following basic features:

- A free-running clock that synchronises to the BBC time-broadcasts;
- A memory for pre-programmed switching of tariffs and loads;
- Able to respond to load-shedding and load-boosting commands;
- A fall-back switching pattern set to the E7 tariff; and
- A random switching-time offset of ± 3 minutes that prevents all Teleswitches switching at the same instant.



Figure 1: A Radio Telemeter (Combined Meter and Teleswitch)

The details required for development of a Teleswitch and about the decoding of LF data are documented in BS7647 [1].

4 Use of the RTS in the SHEPD Licence Area

Electric storage heating has proliferated in areas off the gas grid, as an alternative to solid fuels or oil. Large areas of Scotland, the Highlands and Islands, South West of England, North East of England and London have a significant demand base. The focus of this paper is on the Scottish Hydro-Electric Power Distribution (SHEPD) Electricity Distribution Licence Area operated by Scottish and Southern Energy Power Distribution (SSEPD), which commissioned and directed this work.

In SHEPD use of the RTS dates from around 1993 when it was introduced for load management on Shetland, in response to growing peak demands from storage heating. Other regions followed Shetland, with Orkney receiving a scheme in 1994. Regions where the RTS has been deployed to manage storage heating load include the Shetland Isles, Orkney Isles, Western Isles (Harris, Lewis, N. and S. Uist), Islay, Skye and urban areas such as in Dundee. Many of these areas have their own regional switching programmes that have been set-up to spread-out delivery of charging energy for storage heaters and thus enable it to be delivered economically across the rural electricity networks that supply these areas. The necessity of spreading-out this load can be understood by considering Figure 2, where E7 depicts the after-diversity load profile of a storage-heating customer and 'URLC' depicts the after-diversity load profile of a gas-heated property [2].

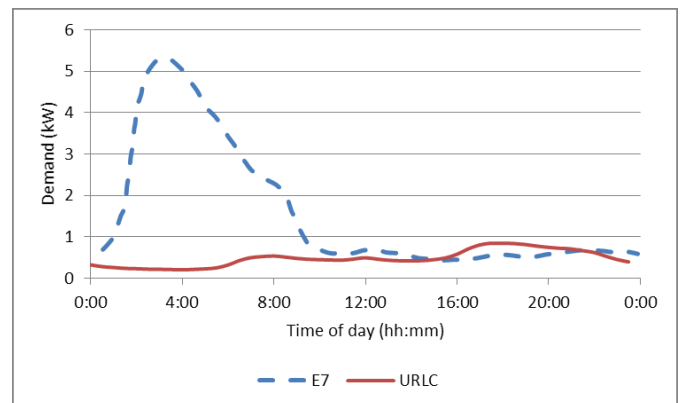


Figure 2: Comparison of the Electricity Demand of Storage Heating and Gas-Heating Customers

The energy required for storage heating is about 4 times that of a gas-heating customer, while the peak electricity demand is around 6 times. The benefit to electricity networks of being able to divide a single overnight charge as depicted in Figure 3 into several smaller chunks of the same energy but requiring less peak power, is clear.

In Schedule 8 of the Distribution Connection and Use of System Agreement (DCUSA, that is the contract between the electricity distributors, suppliers and generators of Great

Britain [3]), a network operating company may declare a Load Managed Area. This means that an adverse change in demand profile would threaten security of supply and such notices have been issued in the past for electric heating areas of SHEPD. Today, the predictability of load managed and controlled by the RTS means that this is not required - these areas rely upon the diversity implemented through the RTS to keep storage-heating demand within the asset ratings of the distribution network.

4.1 Present Utilisation in SHEPD

Of the areas that were studied for this project, only Shetland has a regular (annual) review process that considers whether a change to the programmed storage-heating charge times would be beneficial. Shetland is also the location where this facility is most important, as it is not electrically connected to the mainland and has a limited amount of generation capacity and a relatively weak network. There are 12,500 domestic connections on the Isles, with 8,000 of these being storage-heating customers with charge-times controlled via RTS. The majority of these are on one of ten charging profiles, each with diversified programmes for both water and heating. Some of these are temperature-compensated, that is the duration of the charging period is boosted in cold weather and reduced in warm weather.

There are also a mixture of customer tariff agreements, some of which are reported to be venerable and restrictive, with others that allow the network operator a great degree of flexibility. The charging profiles of the latter were adjusted around 2005 to yield a 4 MW reduction in the Shetland Isles' peak load – the equivalent of one generating set.

The capability to effectively manage load using these tariffs is reducing due to a changing workforce and the business separation of supply and distribution. This leads to new storage-heating connections not being assigned to regionally-diversified charge times.

As will be shown later in this paper, removal of the ability to manage this load would have a severe impact on the cost of running the Isle's electricity system. The facility has clearly been exploited as demonstrated by the wide variety of charge profiles that are in the system today, depicted in Figure 3, where the horizontal black bars indicate the times for which charging is enabled and the overlaid vertical rectangles indicate the tariff times for the popular alternative electric-heating tariffs E7 and E10.

While the majority of charge times do intersect the periods of Economy 7 and 10 tariffs, there are significant charge periods that fall outside these, indicating that any wholesale change from existing Load-Managed charge times to E7 or E10 times would cause peak demand to rise.

The ageing Teleswitch technology has been in short supply in recent years and this has led to a recycling of meters from one area to another. Computing equipment used to programme

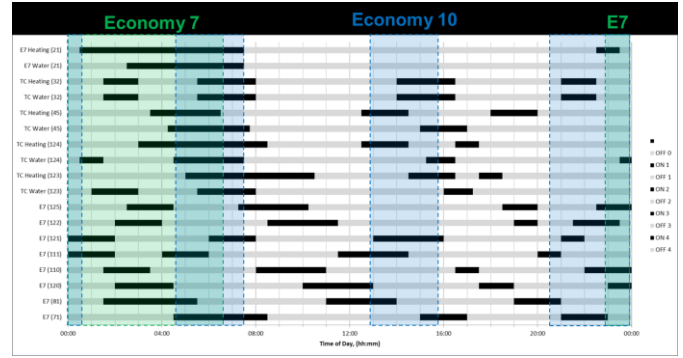


Figure 3: Charge-Time Diversity on the Shetland Isles

the Teleswitches to 'listen' to the correct sequence of charging times is now out-of-date and few personnel are aware of the full functionality and capability of the RTS. These factors are leading to a suspected erosion of the benefits of the RTS in managing load and thus minimising the necessary network investment in these areas. The amount of new storage-heating load being connected in SHEPD has been estimated as about 20 MW per year across the two years that were studied.

4.2 Succession

Modern-day Smart Metering technology has been developed that could deliver the aims of the Load Management concept determined at the time of the development of the RTS. Smart Metering has now been mandated by the EU; 80% coverage by 2020 [4]. As part of the Smart Metering System (SMS) this technology has the potential to improve Load Management and the economics of operating rural, remote electricity networks. For this technology to efficiently and economically replace the RTS, its functionality must be at least that delivered by the RTS; and there must be a method of facilitating transition without putting supply at risk. This means not only the facility for suppliers to update programmes remotely, but also the critical ability for network operators to influence suppliers' switching programmes to suit and protect the operation of networks. Otherwise, electricity customers could be exposed to unnecessary costs for uprating or repairing networks, which could be considerable.

5 Assessing the Value of RTS Load Management in the Shetland Isles

To inform the specifications of the SMS and to provide evidence of the value of the functionality, it is necessary to study what economic impact there might be in removing the present RTS facility. A detailed investigation was undertaken for the Shetland Isles electricity network according to the methodology described in the following section. The aims of the investigation were to identify the network impacts in terms of the numbers and types of assets that would need replacement if the RTS functionality was lost.

5.1 The Value of RTS Functionality

The view taken for this assessment was that if the RTS or a similar system had not been implemented, then those customers would have historically been supplied on an E7 tariff. But what about today? Based on the hypothesis (in vogue at the time of writing) that the programme of tariff-switching times would be simplified, E7 and E10 tariffs would probably be used (the latter being more-suitable for non-storage electric heating such as heat-pumps). There would probably be a spread across these two tariffs. If distributed equally across these tariffs with no overlap in charge times then the relative impact on peak-load would be halved.

Unfortunately, referring to Figure 3, there is considerable overlap in the low-rate tariff periods. Hence it is likely that an allocation between E7 and E10 tariffs would have a similar effect to the impact of all storage-heating customers having the same tariff-switching times. Network impacts have therefore been assessed by applying the E7 tariff originally designed for storage-heaters, to the existing customer-base.

5.2 Assessing Network Impacts

The methodology for assessing network impacts should allow for estimation of the effect on peak demand of changing storage-heater charge start-times to those of the E7 tariff, for key network assets. The following process was employed:

1. Access Primary Substation demands from SSE's data historian;
2. Access details of the numbers of customers whose load is controlled by RTS, their group codes and map to substation locations;
3. Estimate the mean fall-off rate of storage heating load and installed capacity per customer, using the largest load-steps visible from Shetland's generation records and correlating it with the relevant charge-times and numbers of customers;
4. Model the storage-heating load contribution at each Primary Substation using the records of the numbers of RTS customers per-substation and the fall-off rate of storage-heating demand; calculate the RTS-controlled load and other load by subtraction from the recorded substation demands;
5. Calculate the load profile for delivery of an equal amount of heat energy during the E7 charge-times and add to the non-RTS load profile at each substation;
6. Calculate the resultant substation maximum demand and compare against the asset rating; and
7. Repeat steps 4-6 for the 11kV network by calculation of the maximum demand per-circuit and per 11kV/LV transformer; for other distribution circuits and for the whole-Island demand, comparing this against the capacity of generation available.

For Shetland this detailed process revealed that significant numbers of assets would exceed their rating. These assets would require replacement or uprating and are presented in Table 1 below. It also showed that even with today's imperfect Load Management application means that a diversified capacity of about 3 kW per customer is all that is needed for storage-heating, as opposed to the installed capacity of about 6 kW per customer.

| Impacted Asset | Impact |
|----------------------------|---|
| Generation | Additional 72 MW required |
| 33 kV Distribution Network | Uprate 70 km of lines |
| 33kV/11kV Substations | Uprate 6 Primaries |
| 11kV Distribution Network | Uprate 240 km of lines Uprate 50 km of cables |
| 11kV/LV Substations | Replace 220 Ring Main Units Replace 550 Transformers |

Table 1: Network Impact of RTS-Removal for the Shetland Isles Power System

5.3 Assessing Financial Impacts

The financial impact of uprating the generation and distribution networks were calculated from Table 1 and converted to monetary asset values using data supplied by SSE and Distribution Price Control Review Period 5 allowed regulatory expenditures [5].

The resultant costs are presented in Table 2 below.

| Location | Shetland Isles |
|----------------------------|----------------|
| Generation | £31M |
| 33 kV Distribution Network | £6M |
| 33kV/11kV Substations | £5M |
| 11kV Distribution Network | £16M |
| 11kV/LV Substations | £7M |
| Total | £65M |

Table 2: Financial Impact of RTS-Removal for the Shetland Isles Power System

The values presented are regulated asset values and do not include manpower expenses nor the additional costs of installation on Shetland. They should be regarded as indicative, further careful study and planning would be necessitated should the removal of Load Management functionality become a realistic possibility.

6 The Value of Load Management in the SHEPD Licence Area

The Shetland Isles were chosen to receive the most detailed investigation of network impacts, as it was the region for which there was the greatest understanding of both the history of Load Management on the Isles and recent experience of using the system to reallocate load. A similar process was followed for the Orkney Isles, with progressively less detail for the remaining regions in SHEPD.

The result of this process was that, across the SHEPD locations investigated, removal of Load Management functionality would trigger a need to provide about £160M of new electricity generation and distribution assets as presented in Table 3 below.

| Location | Generation | Distribution |
|---------------|------------|--------------|
| Shetland | £31M | £34M |
| Orkney | £14M | £17M |
| Western Isles | £25M | £18M |
| Islay | - | £13M |
| Skye | - | £9M |
| Dundee | - | - |
| Total | £70M | £91M |

Table 3: Financial Impact of RTS-Removal across SHEPD

This shows the very undesirable impact that any reduction in the functionality of the Load Management system could have in storage-heating areas. To avoid the need for this investment, the succeeding Load Management system i.e. the SMS should have *at least* the technical functionality to apply existing diversified charge-times. The industry governance arrangements set up at the time of privatisation and the unbundling of the electricity industry will also need updating to ensure that the “future controllers of load” consider the impact of demand profiles on distribution assets. Network operating companies are working collaboratively via the Energy Networks Association to ensure this.

There are also some other technical features of the RTS that the Smart Metering System should replicate with at-least or better functionality. These are described in the following Section and could be regarded as a minimum level of functionality.

7 Key Features of Load Management that the Smart Metering System Should Provide

This paper has outlined the reasons for the development of the present RTS for Load Management, history of use and value. This experience has shown that there are a number of important functions that should be implemented by the successor SMS, as follow.

7.1 Gradual Pickup of Storage Heating Load

In the early days of the E7 and White Meter tariffs, take-up of the off-peak tariff created a spike in demand as the off-peak rate commenced. This created the need for plant to be held in spinning reserve and caused concern for the CEBG.

To mitigate against large step-changes in load, the RTS meter-specification [1] ensures that each meter has an inbuilt ± 3 minute random offset time applied to their tariff-switching times. The resolution is 7 steps, so for a large population of meters on the same tariff, the load should be seen to increase in steps separated by 52 seconds. To verify this, high

resolution data was processed that captured the two largest steps for Shetland, these are presented in Figure 4.

As can be seen, the transition was not stepped but fairly smooth, the largest instantaneous step being about 1 MW for a group of about 1000 customers; 1 kW per customer. The smooth profile probably indicates that individual Teleswitch clock-times vary slightly.

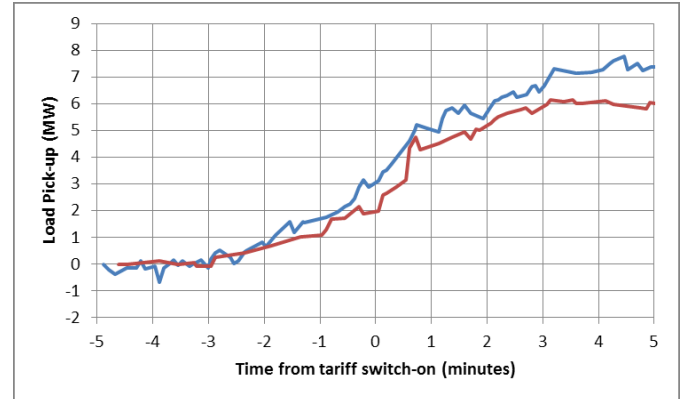


Figure 4: Shetland RTS Load Pickup

On electricity networks, voltage-dips of $>3\%$ should not be exceeded in planning [6]. The severity of the dip depends upon the source impedance and the magnitude of instantaneous load switched. The worst-case voltage dips are experienced at the lowest Fault-Level (FL). For example, at a fairly low LV FL of 2 MVA (3 kA), source impedance is $415 \text{ V} / 2 \text{ MVA} = 0.21 \Omega$. Assuming an R/X (resistance/reactance) ratio of 1.0 at LV and allowing for the flow and return path, the phase-neutral resistance is also 0.21Ω . A 3% voltage step is $3\% * 240\text{V} = 7.2\text{V}$ and is caused at a current of $7.2\text{V} / 0.21 \Omega = 35 \text{ A}$ with a real power of 8.3 kW, just less than the typical installed capacity of water and storage heating (3kW + 6kW). Thus the 7-step load pickup is quite effective in preventing voltage step-changes; these would be experienced under rare circumstances if water and storage-heating were switched at the same instant.

The message for the Smart Metering System is clear – to provide equal-or-better functionality load should be picked up across no less than 6 minutes and in no less than 7 instantaneous steps. Ideally the offsets could be changed after installation if found to be necessary.

7.2 Facility for Regional Per-Customer Charge Time Selection

The present Load Management allows for diversified charge times within groups of customers and for customers to be assigned to different groups. Different methods could be adopted by the SMS, but it is clear that for Load Management purposes, it should be possible to choose from a wide range of charge times. This facilitates both the optimisation of demand where there are small numbers of customers fed from transformers and especially for Island power systems where

electricity system economics are greatly affected by the level of peak demand.

7.3 The Customer's Tariff Agreement should allow Dynamic Charge Time Re-Allocation

The experience gained on Shetland has been that those customers with tariff agreements allowing charge times to be changed without prior notification were the most useful for Load Management purposes. Recent alterations to charge periods had used these customers exclusively.

7.4 Capability to Multi-Cast Load-Drop

When major unplanned events occur (e.g. a significant circuit outage or plant unavailability), electricity supply is at risk. The RTS function to immediately switch-off storage heating load has been used on Shetland about 8 years ago, when supply margins were especially tight and twice to maintain supplies on Uist when the submarine cable connecting it to the mainland had a fault. The ability to switch-off storage heating in emergency situations to maintain electricity supplies that would otherwise be cut-off or rotated on-off supply, is of great benefit for customers.

7.5 Application of Existing Charge Times as Initial SMS Settings

To allow existing levels of demand to be maintained after a transfer of control to the SMS, it should have the capability to accept existing charge time allocations in different regions. This reduces the risk that a transition from RTS Load Management to the SMS equivalent could affect security of supply. It also means that network operating companies would not have to undertake extensive studies to understand how best to allocate storage-heating load, but could apply existing schemes by default without undue concern.

There is broad recognition in the industry that when an RTS meter is exchanged for a Smart Meter the existing switching regime should be maintained. This is to manage customer expectation (because they tend to become familiar with load-switching times) and manage network risk. Some concern remains over what may happen after the exchange. While for the exiting RTS any change to load-switching times is managed by the network operator, with Smart Meters suppliers will be able to change those times without reference or co-ordination with network operators.

The most likely approach for network operating companies to control this risk is likely to be via changes to existing industry code governance.

8 Conclusion

Despite its age and the loss of knowledge about the RTS and its use for Load Management, this study has shown that the GB RTS is providing significant benefits in a number of regions where electric storage heating is prevalent. The design of the RTS and Teleswitch itself has been shown to be

effective in preventing excessive voltage step-change on distribution networks and in allowing the shifting of demand to mitigate needs for investment that could otherwise arise. In most areas, once set up, the system has operated successfully, delivering high levels of predictability with minimal intervention.

The Load Management concept presently implemented by the RTS and due to be succeeded by the SMS, has shown itself to have received significant deployment in electric storage-heating areas. These are typically rural and can be rather remote, where the cost of generating and distributing electricity is high. They also tend to have good renewable energy resources, hence the value of Load Management will grow rather than reduce. Industry governance arrangements will require some changes to ensure that the successor SMS does not raise the risk of operating networks in those areas where RTS Load Management schemes are in place.

This paper has reported that the most useful Load Management has been implemented using the load-shifting capability of customers on 'dynamic' tariff agreements, where the network operator can make changes to charge times, within detrimental impact on comfort, without notifying the customer. This is of great utility for network operators and by virtue of the efficient operation of electricity networks, for the customer too. For the successor SMS it means that a tariff agreement issued by a supplier in an area that needs Load Management should allow this degree of freedom over charging periods. If not, then much value will be lost.

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