Task 3.4: Review of Enablers, Solutions and Top-Down Modelling in TRANSFORM

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1. EXECUTIVE SUMMARY

This report describes the outcomes of Task 3.4 for Work Stream 3 (WS3) of the Smart Grid Forum. Smarter Grid Solutions (SGS) has completed a review of the existing enablers and solutions within the TRANSFORM model and made a set of recommendations regarding top-down modelling. These are outlined in this report.

We have made a number of changes to solution and enabler CAPEX and OPEX assumptions based on our understanding of costs experienced to date in relevant activities and pilot projects, including those under IFI and LCNF funding. It is likely that these assumptions will require further and possibly continued assessment as the industry continues to trial appropriate smart technologies over the next several years. We have also reviewed the mapping of enablers required in support of each solution to reflect our interpretation of recent smart technology trials.

We are grateful to the Smart Grid Forum Work Stream 3 members and other project partners for advice and feedback to our draft report which has enabled us to refine our approach during this project.

Our recommended changes are likely to have increased the overall predicted expenditure in TRANSFORM model outputs, compared with earlier assumptions. In comparison, we would expect that future smart technology trials will enable some reduction in cost estimates to be achieved as solutions move closer to business-as-usual and any uncertainties are reduced.

Overall, we support OFGEM's findings, as recently reported:

"First indications are that investing in some level of smart grids is likely to be justified irrespective of the volume take up of low carbon technologies, but that it is worth waiting until we have more future certainty (i.e. RIIO-ED2) before embarking on a wholesale roll-out."[1].

However, we have identified a number of strategic smart enablers that will provide support for a 'least regrets' policy and will require a number of years from enabler programme initiation through to solution deployment. We would recommend that these 'least regret' opportunities be given early consideration during the RIIO-ED1 price control review and be subject to top-down modelling in TRANSFORM.

We would also refer to OFGEM's earlier approach to the need to establish and fund enhanced systems in advance of their use. This includes where OFGEM and the industry successfully implemented customer quality of supply standards between 2000 and 2003 through the use of a per-customer allowance intended to reflect the likely cost of the reporting systems to be deployed at each DNO. It is possible that some of the strategic enablers identified in TRANSFORM, including communications and data systems, will require an early, least regrets, approach if the industry is to be ready for the deployment of smart solutions in response to low carbon technology take-up.

[1] Strategy consultation for the RIIO-ED1 electricity distribution price control, OFGEM, September 2012

2. INTRODUCTION

Smarter Grid Solutions (SGS) has prepared this report in support of EA Technology's (EATL) earlier and on-going work for Work Stream 3[2] of the Smart Grid Forum. EATL has developed an econometric model, TRANSFORM™[3], which can provide an estimate of the spending profile necessary to prepare and reinforce the GB distribution networks and implement smart solutions so as to meet the future uptake of Low Carbon Technologies (LCT), as forecast/anticipated by the UK Government Department of Energy and Climate Change (DECC).

Our particular focus for this activity is the production of this report covering:

- Review and revise the assumptions and parameters in the model;
- Assist EATL in the re-categorisation of 'top-down' and 'enabling' investments in smart solutions and enablers; and
- Assist EATL in the analysis and grouping of 'top-down' and 'enabling' investments from a national and license area perspective.

SGS has also collaborated with Grid Scientific, who is tasked with a development of earlier 'Tipping Point Analysis' as part of Task 3.5 and their work is reported separately.

Once our recommendations have been acted on by EATL, SGS will also provide support to EATL in interpreting and summarising the changes observed in the output of the TRANSFORM model.

It should be noted by the reader that SGS has not accessed the model in performing this review and has instead worked with the existing documentation and Excel spread sheets that act as inputs to the model. Therefore, it will only be possible to determine the impact of the changes proposed once the model has been re-run with the new data set. This report presents the recommended changes to that data set.

2.1. Summary of Approach

The anticipated uptake of LCTs over the coming decades is expected to lead to significant network development needs across much of the networks of each Distribution Network Operator (DNO). TRANSFORM is understood to provide a measure of likely reinforcement (and hence capital expenditure) due to LCT adoption and separate from other capital expenditure (CAPEX) driven investments, principally those related to 'traditional' load related CAPEX and end-of-life asset replacement (non load-related CAPEX). TRANSFORM also considers the adoption of 'smart solutions' and associated 'enablers' that can act as alternatives or indeed compliment the reinforcements required.

SGS has reviewed each of the solutions and enablers previously created by EATL as inputs to TRANSFORM. In addition, we have given consideration to the likely requirement for a strategic solutions deployment, i.e. a top-down approach, when considering the migration from a traditional/conventional Distribution Network Operator (DNO) to one capable of applying timely

[2] 'Assessing the Impact of Low Carbon Technologies on Great Britain's Power Distribution Networks', EATL, report to SGF WS3, available online at: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=47&refer=Networks/SGF/Publications

[3] TRANSFORM is now a registered trade mark, owned by EATL

smart interventions in order to reduce and/or delay the use of conventional solutions and not be a barrier to LCT uptake.

When considering top-down modelling approaches, we have given specific attention to the need for strategic instead of incremental investment for some enablers, specifically communications (except for 'last mile') and data-systems. We expect that the deployment of 'an internet of things', i.e. a communications and data network encompassing DNO low voltage (LV) assets and either smart meters or other LV-fringe devices, will take a similar amount of time as DECC's planned deployment of smart meters, i.e. six or more years. We are aware that the deployment of SCADA systems throughout GB took over 5 years, starting with Area Board trials and CEGB's GI74 in the early 1970's and ending around 1985.

We have included a representative level of operational expenditure (OPEX) for each enabler and solution. We made use of similar high performance computing deployments to estimate OPEX for smart enablers and solutions. We made use of OFGEM DPCR public data to derive a reasonable ratio of OPEX to asset value for conventional solutions.

We have taken account of experience of DECC's procurement of communications and data services provider roles for the Data Communications Company (DCC). To date, we anticipate that the first generation of DCC systems will not include a wide range of operational smart grid functionality but will be limited to routine meter reading data collection and 'last gasp' power outage alarming, possibly delayed to avoid reporting auto-reclose events.

Finally, we have made a series of recommendations for further development of TRANSFORM and the data set it utilises, which could be considered in the on-going governance of the model[4].

[4] www.eatransform.com

3. GENERAL COMMENTS ON THE TRANSFORM MODEL

We appreciate the significant effort that has been expended to date on TRANSFORM, by EATL, members of SGF WS3 and others. This has led to the development of a set of investment profiles intended to reflect different scenarios, as guided by DECC and DfT, inter alia.

We have set out here some comments about TRANSFORM that are meant to ensure that the model output is acknowledged as 'best available' but also based on 'heroic assumptions'. The use of assumptions and the typical errors present in such models will mean that TRANSFORM output cannot be treated as precision data and instead should be taken to provide an indicative order of magnitude. This does not detract from the usefulness of the model as a forecasting tool.

3.1. Errors in econometric models

We were not asked to provide a measure of the precision and/or accuracy achieved by TRANSFORM and we have not provided any; however, as an econometric model, TRANSFORM is exposed to a variety of possible sources of error. This should be borne in mind when reviewing and making changes to the data utilised by TRANSFORM, or considering the future governance of the model and accompanying data set. Errors in econometric models were summarised in a paper[5] by Professor Cubbin of City University, for Water UK, and are listed below with comments about how TRANSFORM may be affected by such errors (please note that these are not intended to represent a comprehensive set of error factors):

Table 1: Potential sources of error in econometric models

Five sources of error present in econometric models identified in Professor Cubbin's report	**What this means for TRANSFORM**
A. Even with totally accurate data and models, estimates are just estimates and subject to sampling error as long as there are limited observations	EATL has summarised the variables and data sources used in TRANSFORM in its WS3 report, including variables such as: • TRANSFORM has classified all network feeders into a limited set. It's possible/likely that there are sampling errors from this approach which may lead to an error in estimation of the number of feeders which require reinforcement in any LCT scenario. • TRANSFORM limits itself to three days of load profiles in a year, to model likely generation costs and schedules. This will likely lead to incorrect selection of enablers/solutions.

[5] Assessing Ofwat's Efficiency Econometrics, A report for Water UK, March, 2004, Professor John Cubbin, City University

B. There may be error in the measurement of the dependent variable	One example of this is that TRANSFORM does not include metered (or simulated) consumption data for 29 million customers but relies on static load profiles. These same profiles are already put to good use e.g. in CDCM but they only influence the share of any tariff class while TRANSFORM uses these same profiles to drive the need for and selection of solutions leading to changes in CAPEX.
C. There may be variables excluded from the analysis	There are a number of variables excluded, listed in EATL's report at Appendix A, Section 10.3 (What's Included and what's not including in the model), such as asset replacement for end of life. This is likely to mean that TRANSFORM underestimates the CAPEX required for LR reinforcement as a result of increased network loadings under an LCT scenario.
D. The explanatory factors may themselves be proxies and/or subject to errors of measurement	One example here is that customer types have been approximated from regional analysis data that does not map directly to DNO territories and does not exactly correlate with LCT impact on future customer demands. This will likely mean that TRANSFORM will suffer from additional inaccuracies when used for one DNO region.
E. The wrong mathematical form may have been chosen to approximate the relationship between costs and their drivers	One example of this is the assumption that all enabler/solutions prices follow one of five cost profiles (detailed at EATL's report, Section 13.4). In reality, cost profiles will be more volatile, with larger variations over time and are less easily forecasted. The recent fluctuations in metals prices, if used to inform conventional solution price increases, would have a significant impact on conventional solution costs over the modelling period. This will lead to imprecise enabler/solution selection by TRANSFORM, exacerbated when considering RIIO-ED2 and later periods.

3.2. Asset Lifetime and OPEX

Each enabler and solution can include an estimate of the operating costs (OPEX) attributable and we have reviewed the level of OPEX assigned. We have aimed for a mid-point estimate and include our reasoning below. We have made use of public-domain information from earlier OFGEM documents in this analysis.

3.2.1. OFGEM, RIIO-T1

Estimating OPEX can be difficult. During RIIO-T1[6], OFGEM appointed a consortia of consultants to review direct OPEX performance for RIIO.

Separate from direct OPEX, there are closely associated indirect costs, expected to include:

- Operational IT and Telecoms;
- Operational Property Management;
- Operational Training;
- Health, Safety and Environment;
- Control Centre;
- Stores and Logistics;
- Network Policy (including R&D);
- Engineering Management and Clerical Support;
- Project Management;
- Network Design and Engineering;
- System Mapping; and
- Vehicles and Transport.

We believe that our use of typical OPEX/RAV ratios will mean that each solution/enabler includes a representative proportion of these indirect costs.

Further to the above, business support costs are also incurred in DNO activities, including:

- IT and Telecommunications;
- Property;
- Human resources and non-operational training;
- Finance and regulation;
- Insurance;
- Procurement (excluding stores and logistics); and
- CEO and other corporate functions.

It is expected that these costs will be affected by the increased activities in response to LCT deployment but these are not included in any TRANSFORM or similar modelling.

3.2.2. e-FISCAL

EUROPEAN STUDY OF *European dedicated High Throughput and High Performance Computing (HTC/HPC) e-Infrastructures for research*[7]

[6] From: OFGEM RIIO T1 Tools for costs assessment, March 2011.

[7] Computing e-Infrastructure cost calculation at National and European level, July 2012

This study provides some indications of high performance computing OPEX/CAPEX ratios. It indicates that TOTEX may be split as 30/70% CAPEX/OPEX with personnel costs accounting for up to 50% of TOTEX.

Using ratios identified in e-Fiscal for smart solutions/enablers and typical asset lifetimes of 10 years plus an expectation of 30/70 CAPEX/OPEX over the asset lifetime gives an annual OPEX rate of 19.9% (at a discount rate of 3.5%).

Similar calculations for 15 and 20 years gives:

15 years, OPEX rate = 12.1%

20 years, OPEX rate = 8.3%

For comparison, a 40-year OPEX profile would be set at 2.8% for a similar CAPEX/OPEX ratio.

3.2.3. Opex for conventional solutions

TRANSFORM includes a variety of conventional solutions but, until now, each of these has not included any OPEX. An OPEX allowance would enable the TRANSFORM model to reflect the operating costs involved in routine and fault maintenance of such assets; for example, cable circuits typically experience between 5 and 10 faults each year per 100km, while overhead circuits average fault rates are about 15 faults per year per 100km. Switchgear, transformers and other conventional assets are subject to routine maintenance as well as fault repairs, albeit at a low frequency. Typical indirect operating costs will also be captured by the use of this ratio.

We have reviewed the 2005-2010 price control review data[8] that lists OPEX and regulated asset value (RAV) for a selection of licenced area. Over the 2005-2010 period annual forecast OPEX and RAV shows a weighted average OPEX at 6.8%, when expressed as a ratio of RAV. We have identified an annual OPEX of 6% of CAPEX for conventional solutions as a mid-point estimate from this methodology.

3.2.4. Alternative OPEX comparators

It is possible to derive an OPEX annual increase factor by inspection of earlier OFGEM work associated with composite scale variables. While these variables may be limited in their application and precision, they can provide an indication of OPEX increases due to increases in units distributed and network length, each of which will increase for LCT reinforcement; an examination of these factors shows an annual OPEX increase approximating to 1% for conventional solutions and enablers.

When considering smart solutions and enablers, involving significant increases in data, communications and IT, it is more appropriate to make comparisons with a similar technology service provider and we have compared total GB DNO OPEX with total BT Openreach OPEX. This provides us with a smart OPEX rate of 4x conventional, i.e. 4%. Discussions with WS3 members and our own experience of likely additional costs for some smart methods has provided the opportunity to divide smart enablers/solutions into ‘simple smart’ (such as RMU actuators, LV link boxes) and ‘complex smart’ (such as active control systems). An annual OPEX rate of 10% for ‘complex smart’ is considered reasonable in these circumstances.

[8] OFGEM Electricity Distribution Price Control Review, Final Proposals, November 2004

3.2.5. Asset lifetimes

From earlier OFGEM documents, primary plant is typically assigned a lifetime of between 40 and 90 years; this reflects the significant lifetimes seen in traditionally specified, sourced, installed and maintained equipment including cables, conductors, transformers and switchgear.

Secondary equipment, such as protection relays, are similar in construction to electronic smart meters and it is informative that the best assembled electronic meter has a lifetime of between 15 and 20 years[9] to reflect typical electronic component in-service failure rates.

IT systems are typically high annual cost items and annual software updates (including any on-going cyber security provisions) and annual licences[10] are likely to require additional expenditure over routine maintenance. An overall annual OPEX/maintenance rate of 8% CAPEX could be expected to represent these costs.

Where enablers or solutions are not yet available in the marketplace, it is possible to consider an increase in annual OPEX to reflect likely additional operational costs, including training and other 'start-up' issues; it is also likely that any first generation solution/enabler may experience a shorter than normal asset life, with second generation devices/solutions likely to demonstrate reduced CAPEX and OPEX costs.

3.2.6. What this means for TRANSFORM

We have made efforts to identify the additional incremental OPEX arising from LCT CAPEX using two methods for conventional and two methods for smart enablers/solutions.

With the guidance of WS3 members, we have recommended the more conservative methods of deriving OPEX rates.

Our work on deriving OPEX rates was presented to the SGF WS3 group (meeting on 31st January, 2013) for comparison. On balance, the WS3 group has recommended that asset lives and OPEX rates be estimated as per the following table.

Table 2: Asset lifetime and OPEX assumptions

Asset type	Assumed lifetime	Assumed annual OPEX
Conventional / primary plant	40 years or higher	1%
'Simple smart'	20+ years	4%
'Complex smart'	15-20 years	10%

[9] There are informal references in OFGEM's Meter Examiner Service to these typical rates derived while establishing Meter Approvals, prior to MID Certification.

[10] Reference to 22% annual software licences at: http://www.informationweek.com/software/enterprise-applications/software-maintenance-fees-time-for-this/212902014

3.3. Linkage with CDCM

The DNOs and OFGEM have recently concluded a review of Common Distribution Charging Methodology (CDCM) and EHV Distribution Charging Methodology (EDCM). As a part of this work, each DNO is required to prepare a 500MW model which *"... must be designed as an increment serving loads that have the same topography, diversity and other characteristics as the actual loads on the existing network. In particular, customers' locations and consumption patterns should be representative of reality in the licensee's area. ... must reflect current design practice and the assumptions about utilization".*

While it has been established earlier that TRANSFORM will not, at present, interact with the 500MW model, it is for consideration that some form of interface will be required as any future TRANSFORM scenario moves from forecasting into DNO short-term strategic plans.

3.4. Optimism Bias

3.4.1. What is Optimism Bias?

Optimism Bias (OB) is specified in the Treasury Green Book[11] and the Mott MacDonald Report[12]. HM Treasury commissioned Mott MacDonald (MMD) to undertake a study to review the outcome of large public procurement projects in the UK over the previous 20 years as part of an exercise to revise the Green Book.

Optimism bias is the demonstrated systematic tendency for appraisers to be over-optimistic about key project parameters. It must be accounted for explicitly in all appraisals, and can arise in relation to:

- Capital costs;
- Works duration;
- Operating costs; and
- Under delivery of benefits.

In each case, it is expected that early estimates will be refined in the light of experience during any project. However, some observers note that optimism bias may unreasonably inflate project budget costs leading to spending up to that limit. Alternative approaches include separate accounting and management of a contingency fund to cover unforeseen eventualities, as per Olympic Delivery Authority. For comparison, recent projects have also made use of Reference Class Forecasting[13], including the London Crossrail and Edinburgh Trams projects – this alternative has not been reviewed further.

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[11] Treasury Green Book: Appraisal and Evaluation in Central Government, 2003, as amended, 2011 plus Supplementary Green Book Guidance, 2003

[12] Mott MacDonald, Review of Large Public Procurement, 2002

[13] Kahneman and Tversky developed the theories of reference class forecasting, Flyvbjerg and COWI developed the method for its practical use in policy and planning.

3.4.2. How is Optimism Bias applied?

OB adds an inflator to each estimate of CAPEX in any government project. The inflator is typically selected from between an upper and lower bound, intended to represent the range of OB identified in earlier government projects of a similar composition.

The MMD report states: *"The upper bound values recommended for use when calculating optimism bias represent the optimism bias level to expect for current projects without effective risk management and bad scope definition, and are the starting point for calculating optimism bias for projects. These upper bound values reflect the average historic values because the average historic values are similar to the highest values for optimism bias currently being recorded for recently completed projects that have experienced high levels of optimism in their project estimates.*

The lower bound values identified represent the optimism bias level to aim for in current projects with effective risk management by the time of contract award."

Typical OB ranges from MMD report are provided in Table 3.

Table 3: Optimism Bias Guidelines

Project Type	Optimism Bias (%) [2]			
	Works Duration		CAPEX	
	U	L	U	L
Non-standard Buildings	39	2	51	4
Standard Buildings	4	1	24	2
Non-standard Civil Engineering	25	3	66	6
Standard Civil Engineering	20	1	44	3
Equipment/Development	54	10	200	10
Outsourcing	N/A	N/A	41*	0*

* The optimism bias for outsourcing projects is measured for operating expenditure, OPEX

Meanwhile, it may be important to acknowledge that DNOs are not government departments and their capital budgets, as agreed at price controls, are not subject to such levels of optimism bias. This implies that all conventional solutions/enablers should not include an optimism bias or that these OB values should be validated against recent relevant DNO project, particularly IFI and LCNF projects which involve smart enablers/solutions.

3.4.3. What level of Optimism Bias is appropriate for TRANSFORM?

An OB of 66%, as used throughout early TRANSFORM modelling, appears open to challenge. The range of bias typically applied for technology-driven activities is between 10% and 200%[14]. There are some possibly useful indicators of bias in recent government assessments: A recent review of OB in the DECC smart meter programme[15] identified a range of OBs for each part of the programme.

[14] Mott MacDonald, Review of Large Public Procurement, 2002

[15] Smart Meter Roll Out: Risk & Optimism Bias Project, Baringa for DECC, Feb 2009

Table 4: Optimism Bias as per DECC Smart Meter Programme

Programme Segment	Optimism Bias (applied to CAPEX)
Meter CAPEX	15% (was 45% in earlier assessment)
RTD CAPEX	15%
Communications costs – general	Zero
Communications costs – Radio	20% (was 60%)
Communications costs –PLC, WiMax	30% (was 60%)
Communications costs –broadband/3G	Zero (was 30%)
IT & Settlement systems	50% (was 135%)
Installation CAPEX	10% (was 45%)
Communications costs –HAN	15% (was zero)

3.4.4. Assignment of optimism bias

We have found it useful to categorise each enabler and solution according to its readiness for widespread deployment in a business as usual environment, as shown in Figure 1. Naturally, we expect that those enablers and solutions at the right hand side of the diagram will involve greater uncertainty in estimates of cost, benefits and readiness for deployment and we have also used the diagram to remind ourselves that any development from first idea through to business-as-usual will likely require innovation funding, which is also separate from the TRANSFORM model.

Figure 1: Enabler/Solution maturity mapping

It is possible to assign a measure of OB according to the readiness of each solution/enabler, as presented in Table 5.

Table 5: Recommendation for optimism bias allocation

Solution/enabler readiness	Possible Optimism Bias
Business As Usual	10%
Shovel Ready	20%
In Trials	30%
Out there...	50%

Taking these OBs gives a possible revised optimism bias for each enabler, as shown in Table 6.

Table 6: Suggested optimism bias allocation to enablers

	Original OB	Revised OB
Advanced control systems - EHV	66%	50%
Advanced control systems - HV	66%	50%
Advanced control systems - LV	66%	50%
Communications to and from devices - LAST MILE ONLY	66%	10%
Design tools	66%	30%
DSR - Products to remotely control loads at consumer premises	66%	10%
DSR - Products to remotely control EV charging	66%	30%
EHV Circuit Monitoring	66%	10%
HV Circuit Monitoring (along feeder)	66%	10%
HV Circuit Monitoring (along feeder) w/ State Estimation	66%	10%
HV/LV Tx Monitoring	66%	10%
Link boxes fitted with remote control	66%	10%
LV Circuit Monitoring (along feeder)	66%	10%
LV Circuit monitoring (along feeder) w/ state estimation	66%	50%
RMUs Fitted with Actuators	66%	10%
Communications to DSR aggregator	66%	30%
Dynamic Network Protection, 11kV	66%	50%
Weather monitoring	66%	10%
Smart Metering infrastructure - DCC to DNO 1 way	66%	30%
Smart Metering infrastructure -DNO to DCC 2 way A+D	66%	50%
Smart Metering infrastructure -DNO to DCC 2 way control	66%	50%
Phase imbalance -smart meter phase identification	66%	30%
Phase imbalance -HV circuit	66%	10%
DNO data architecture	66%	10%
COMMS FABRIC	66%	10%
COMMS BACK-HAUL	66%	10%

4. SUMMARY OF RECOMMENDED CHANGES TO DATA SET

4.1. Enablers/Solutions

The following tables provide a high-level summary of various suggested changes to enablers and solutions plus an estimate of the nature of the impact of the change on the output of TRANSFORM.

Table 7: Suggested changes to existing Solutions

Solution	**Comments**	**Impact on TRANSFORM**
ANM Solutions	Changes made to EATL spread sheet estimates are intended to reflect recent experience on schemes throughout GB.	It isn't clear if the changes made will increase or decrease TRANSFORM model output.
Generator Side Response	We have proposed changes to the formation of each GSR solution – we expect that existing generation will require payments via contract while new generation may not and may be bound by lower connection charges, if appropriate.	It is unclear if our proposed changes will increase or decrease TRANSFORM output.
CONVENTIONAL SOLUTIONS SET	We have not made any changes to these solutions and expect that DNOs and EATL are already able to estimate CAPEX in these cases. These solutions were adjusted for 2012 money values. We have also recommended that an appropriate level of OPEX is added to all conventional solutions.	It is likely that our recommended changes to OPEX will lead to an increase in TRANSFORM output.
Additional Conventional Solution opportunity – 20kV upgrade	As mentioned above, it is possible to consider a small CAPEX increase as a means of achieving a significant gain in headroom by procuring 20kV apparatus for 11kV networks, in the same way that the industry changed from 6.6kV to 11kV during 1960's – this would require careful treatment of the 'switch-over' at some later calendar year.	No change to TRANSFORM unless agreed.
Temporary and Permanent meshing – all voltages	Likely to meet some practical issues around safety and fault level – understand that London/elsewhere are removing mesh networks for these reasons.	Likely to remove meshing from selection or demote its position on merit order.
Switched Capacitors – all voltages	I&C Customers have been using capacitors for years – proven technology and CAPEX/OPEX set to reflect market costs.	Our recommended changes are expected to lead to a decrease in TRANSFORM model

		output.
Novel Infrastructure – all voltages	It is likely that any novel replacement for conventional technologies will be priced at a premium (early adopter pricing) – but continued use will only follow if novel outperforms conventional. We recommend a review of conventional vs novel. For example, novel EHV UG cable is £900k vs conventional EHV UG major at £5M and EHV UG minor at £1.2M	It is unclear if our proposed review and any consequential changes will increase or decrease TRANSFORM output.
RTTR for LV	It isn't clear that RTTR for LV overhead or underground circuits will outperform existing 'run to fail' approach, albeit with improved network performance. Nor is it clear that RTTR can be easily implemented without LV switchgear upgrading	Likely to remove RTTR-LV from selection or demote its position on merit order.
SFCL	Increased OPEX to reflect refrigeration costs – needs to be inserted into losses although that would exclude these from cost considerations. (TRANSFORM losses are for information only)	Our recommended changes are expected to lead to an increase in TRANSFORM model output.
Enhanced Automatic Voltage Control – LV PoC	We expect per-customer installed devices to cost more than £2000 per feeder – we took PowerPerfector / Vphase devices as typical components and assumed about 5 devices per feeder.	Our recommended changes are expected to lead to an increase in TRANSFORM model output.
Enhanced Automatic Voltage Control – LV circuits	Not new technology – DNOs have used voltage regulators for many years although technology may require mods for underground deployment.	Our recommended changes are expected to lead to an increase in TRANSFORM model output.
Enhanced Automatic Voltage Control – HV and EHV circuits	These would appear to resemble common practice in NA – individual circuit regulators with separate fixed tap transformers. We would expect these to involve considerable CAPEX at typical HV circuit ratings.	Our recommended changes are expected to lead to an increase in TRANSFORM model output.
Enhanced Automatic Voltage Control – HV/LV transformer	Capex adjusted to reflect our experience of 'early adopter' pricing on such devices – we have assumed that this will involve the installation of a replacement transformer with on-load tap changer.	Our recommended changes are expected to lead to an increase in TRANSFORM model output.
Embedded DC – all voltages	We are not aware of any demonstration projects which would provide appropriate cost estimates/comparators. We note that at present, these solutions do not include a year available so that TRANSFORM model will presumably not pick	Our recommended changes may not affect TRANSFORM model output.

	these options. We would recommend that these solutions are reviewed in the light of any yet-to-be-published reports.	
Electrical Energy Storage – all voltages	We are unsure if these devices will deliver an in-service life of 20 years and would recommend a review of this assumption taking the outcomes of relevant LCNF projects.	Our recommended changes are expected to lead to an increase in TRANSFORM model output.
D-FACTS – all voltages	We have not identified any comparator price points and would recommend a review of the assumptions made here following trials.	We have not made any changes to the assumptions in TRANSFORM.

Table 8: Suggested changes to existing Enablers

Enabler	Comments	Impact on TRANSFORM
Data Management and Systems	New enabler introduced to represent the need for a major investment in data management hardware, software and associated data in order to facilitate operational smart grid solutions. Each DNO will need to consider how best to represent existing investments (i.e. the starting point) within costs and parameters.	TRANSFORM may not be able to easily include this investment that will take place over a number of years. These enablers will need to be excluded if DNOs elect to model those costs outside TRANSFORM.
Advanced Control Schemes	Changes made to EATL spread sheet estimates are intended to reflect our expectations of ACS.	Our recommended changes are expected to lead to an increase in TRANSFORM model output.
Distribution State Estimation	Changes made to EATL spread sheet estimates are intended to reflect our expectations of DSE, while the technology remains some years away from demonstrations and deployment at lower voltage levels.	It isn't clear if the changes made will increase or decrease TRANSFORM model output.
Design Tools	Changes to EATL spread sheet intended to reflect experience from recent IFI project in this subject area.	Our recommended changes are expected to lead to an increase in TRANSFORM model output.
LV Consolidated Monitoring	As mentioned above, we have recommended a single enabler to replace a number of other enablers, all focused on monitoring at HV/LV substations.	Our recommended changes are expected to lead to a decrease in TRANSFORM model

		output.
Communications	We have prepared three 'interlocking' communications enablers: • Communications Fabric; • Communications Backhaul; and • Communications Last Mile.	It is likely that our recommended changes will lead to an increase in TRANSFORM output.
Smart Metering Infrastructure	It remains unclear whether DECC's procurement of DCC/DSP/CSP will enable one-way or two-way communications with multicast control within operational timescales. To this end, we have included a set of communications and data management enablers.	It is likely that our recommended changes will lead to an increase in TRANSFORM output. As a high OPEX, low/no CAPEX enabler, DNOs may elect to model these enablers outside TRANSFORM instead.
Monitoring waveform quality at EHV	It is likely that modern EHV electronic protection relays will already include some appropriate functionality so that this enabler may not involve CAPEX.	No changes yet made to enabler assumptions – these changes would lead to a reduction in TRANSFORM output.
HV Circuit Monitoring (along feeder) w/ State Estimation	Set year available to 2020 to reflect development required before SE is readily adoptable.	It is likely that our recommended changes will lead to an increase in TRANSFORM output, although enabler would now not be picked for early LCT reinforcement requirements.
EHV and HV Circuit Monitoring (along feeder)	Increased CAPEX to reflect understanding of monitoring required	It is likely that our recommended changes will lead to an increase in TRANSFORM output.
DSR - Products to remotely control EV charging	We have increased CAPEX to reflect likely harsh environment involved here plus additional costs in customer-side access for maintenance and for routine communications / software licences etc.	It is likely that our recommended changes will lead to an increase in TRANSFORM output.
DSR - Products to remotely control EV charging and DSR - Products to remotely control loads at consumer premises	Increase CAPEX to reflect expected costs involved in these activities.	It is likely that our recommended changes will lead to an increase in TRANSFORM output.
Design Tools	Significant increase in CAPEX to reflect	It is likely that our

	experience gained from recent IFI project.	recommended changes will lead to an increase in TRANSFORM output.
Advanced Control Systems	Significant increase in CAPEX to reflect experience of SCADA/DMS installation and maintenance/licence costs.	It is likely that our recommended changes will lead to an increase in TRANSFORM output.
ENABLER – Solution mappings	We have made changes to the mapping of enablers required for each specific solution. These are listed on a separate spreadsheet, to be attached to the final report. In brief, we have added about 273 enabler mappings to the solution set (for comparison, there were 53 mappings originally).	We anticipate that these additional mappings will lead to an increase in TRANSFORM model output.

4.1.1. Enablers/Solutions Mapping

Table 9: Updated Enablers/Solutions mapping

	Advanced control systems	Communications LAST MILE	Comms BACK HAUL	Comms FABRIC	DATA SYSTEMS	Design tools	DSR - at consumer premises	DSR - EV charging	EHV Circuit Monitoring	HV Cct Monitor feeder	HV Cct Monitor - feeder & SE	HV/LV Tx Moniroting	Link boxes / remote control	LV Cct Monitor/ feeder	LV cct monitor feeder & SE	LV feeder monitoring at S/S	LV feeder monitor - S/S & SE	RMUs Fitted with Actuators	Comms to DSR aggregator	Dynamic Net Protection, 11kV	Weather monitoring	Monitoring PQ (EHV/HV Tx)	Monitor PQ (HV/LV Tx)	Monitor PQ (HV feeder)	Monitor PQ (LV Feeder)	S.Meter: DCC-DNO 1 way	S.Meter: DCC-DNO 2 way A+D	S.Meter: DCC-DNO 2 way control	Phase imbalance - LV dist s/s	Phase imbalance - LV circuit	Phase imbalance via smart meter	Phase imbalance - 3ph.LV cust.	Phase imbalance -HV circuit
Active Network Management - Dynamic Network Reconfiguration - EHV	1	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Active Network Management - Dynamic Network Reconfiguration - HV	1	1	0	0	0	0	1	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Active Network Management - Dynamic Network Reconfiguration - LV	1	1	0	0	0	0	0	0	0	1	1	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D-FACTS - EHV connected STATCOM	1	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D-FACTS - HV connected STATCOM	1	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	1	0	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0
D-FACTS - LV connected STATCOM	1	1	0	0	0	0	0	0	0	0	1	0	1	1	0	0	0	0	0	1	1	1	0	0	0	0	0	0	0	0	0	0	0
Distribution Flexible AC Transmission Systems (D-FACTS) - EHV	1	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Distribution Flexible AC Transmission Systems (D-FACTS) - HV	1	1	0	0	0	0	1	0	0	0	0	0	0	0	1	0	1	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0
Distribution Flexible AC Transmission Systems (D-FACTS) - LV	1	1	0	0	0	0	0	0	0	1	1	0	1	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0
DSR_DNO to Central business District DSR	0	1	0	1	1	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DSR - DNO to residential	0	1	0	1	1	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DSR_DNO to aggregetor led EHV connected commercial DSR	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DSR_DNO to EHV connected commercial DSR	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DSR_DNO to aggregetor led HV commercial DSR	0	1	0	1	1	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DSR_DNO to HV commercial DSR	0	1	0	1	0	0	1	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
cal Energy Storage_HV Central Business District (commercial building level)	0	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electrical Energy Storage_EHV connected EES - large	1	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electrical Energy Storage_EHV connected EES - medium	1	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electrical Energy Storage_EHV connected EES - small	1	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electrical Energy Storage_HV connected EES - large	1	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electrical Energy Storage_HV connected EES - medium	1	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electrical Energy Storage_HV connected EES - small	1	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electrical Energy Storage_LV connected EES - large	1	1	0	0	0	0	0	0	0	0	1	0	1	1	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0
Electrical Energy Storage_LV connected EES - medium	1	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electrical Energy Storage_LV connected EES - small	1	1	0	0	0	0	0	0	0	0	1	0	1	1	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0
BLANK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Embedded DC Networks_Embedded DC@EHV	0	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Embedded DC Networks_Embedded DC@HV	0	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Embedded DC Networks_Embedded DC@LV	0	1	0	0	0	0	0	0	0	0	1	0	1	1	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0
BLANK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EAVC - HV/LV Transformer Voltage Control	0	1	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EAVC - EHV circuit voltage regulators	0	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EAVC - HV circuit voltage regulators	0	1	0	0	0	0	1	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EAVC - LV circuit voltage regulators	0	1	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EAVC - LV PoC voltage regulators	0	1	0	0	0	0	0	0	1	0	1	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fault Current Limiters_EHV Non-superconducting fault current limiters	0	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fault Current Limiters_EHV Superconducting fault current limiters	0	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fault Current Limiters_HV reactors - mid circuit	0	1	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fault Current Limiters_HV Non-superconducting fault current limiters	0	1	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fault Current Limiters_HV Superconducting fault current limiters	0	1	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Generator Constraint Management GSR - EHV connected generation	0	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Generator Constraint Management GSR - HV connected generation	0	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Generator Constraint Management GSR - LV connected generation	0	1	0	0	0	0	0	0	1	0	1	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Generator Providing Network Support e.g. Operating in PV Mode - EHV	0	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Generator Providing Network Support e.g. Operating in PV Mode - HV	0	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Generator Providing Network Support e.g. Operating in PV Mode - LV	0	1	0	0	0	0	0	0	1	0	1	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Local smart EV charging infrastructure_Intelligent control devices	0	1	0	0	0	0	0	0	0	0	1	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
v Types Of Circuit Infrastructure_Novel EHV tower and insulator structures	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Types Of Circuit Infrastructure_Novel EHV underground cable	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ew Types Of Circuit Infrastructure_Novel HV tower and insulator structures	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Types Of Circuit Infrastructure_Novel HV underground cable	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Permanent Meshing of Networks - EHV	0	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Permanent Meshing of Networks - HV	0	1	0	0	0	0	1	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Permanent Meshing of Networks - LV Urban	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Permanent Meshing of Networks - LV Sub-Urban	0	1	0	0	0	0	0	0	1	1	1	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BLANK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RTTR for EHV Overhead Lines	0	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RTTR for EHV Underground Cables	0	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RTTR for EHV/HV transformers	0	1	0	0	0	0	0	0	0	0	1	0	1	1	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0
RTTR for HV Overhead Lines	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RTTR for HV Underground Cables	0	1	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RTTR for HV/LV transformers	0	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RTTR for LV Overhead Lines	0	1	0	0	0	0	1	0	1	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RTTR for LV Underground Cables	0	1	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Switched capacitors - EHV	0	1	0	0	0	0	0	0	1	0	1	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Switched capacitors - HV	0	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Switched capacitors - LV	0	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Temporary Meshing (soft open point) - EHV	1	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Temporary Meshing (soft open point) - HV	1	1	0	0	0	0	1	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Temporary Meshing (soft open point) - LV	1	1	0	0	0	0	0	0	1	1	1	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BLANK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BLANK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LV Underground network Split feeder	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LV New Split feeder	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LV Ground mounted 11/LV Tx	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LV underground Minor works	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LV underground Major works	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LV overhead network Split feeder	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LV overhead network New Split feeder	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LV Pole mounted 11/LV Tx	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LV overhead Minor works	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LV overhead Major works	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HV underground network Split feeder	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HV underground New Split feeder	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Large 33/11 Tx	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HV underground Minor works	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HV underground Major works	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HV overhead network Split feeder	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HV overhead New Split feeder	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small 33/11 Tx	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HV overhead Minor works	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HV overhead Major works	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EHV underground network Split feeder	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EHV underground New Split feeder	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EHV underground Minor works	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EHV underground Major works	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EHV overhead network Split feeder	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EHV overhead New Split feeder	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EHV overhead Minor works	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EHV overhead Major works	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

5. DETAILED REVIEW OF PRIORITY SOLUTIONS AND ENABLERS

In conducting our review, we gave priority to those solutions and enablers where we consider that our recommendations may cause the most significant changes in model output. These are:

- Enablers:
  - Advanced Control Schemes;
  - Communications Infrastructure (including back-office and last-mile);
  - Design Tools;
  - Distribution State Estimation;
  - Data Management; and
  - LV consolidated monitoring.
- Solutions:
  - Generator Side Response;
  - Active Network Management; and
  - Real Time Thermal Ratings.

These priority solutions and enablers were agreed in discussion with EATL and are described in more detail in the following sections. The above lists include the introduction of 'Active Network Management' as a new solution in the model and 'Data Management' as a new enabler. All other items in the list above pre-existed this review by SGS and a set of recommendations has been made to improve the data associated with them and how they are treated within the TRANSFORM model.

The TRANSFORM model relies on apportioning costs on a per feeder basis; this should be borne in mind by the reader while reviewing the following sections.

5.1. Enablers

5.1.1. Advanced Control Schemes

Advanced Control Schemes (ACS) represent the evolution of network Supervisory Control And Data Acquisition (SCADA) systems (or their replacement/equivalent network management system(s)) as they proliferate down through the voltage levels and become the conduit through which control room engineers observe multiple downstream devices and systems, including Active Network Management, Commercial Aggregators and Distribution Automation. Irrespective of where new devices, systems or operational functionality is installed (i.e. centralised or distributed) there will be a requirement to provide DNO operational teams with a near real-time overview of the devices, LCTs and systems that make up the smart grid. We have endeavoured to ensure that our cost estimate for this ACS enabler reflects this requirement.

5.1.1.1. Advanced Control Schemes at LV

The addition of the LV network to the traditional network management function represents a substantial increase in scale. Maintaining visibility of the network, data validation and exchange with multiple thousands of devices and other operational and enterprise systems will place a new requirement on network management systems. It has been assumed that this will involve the adoption of something akin to existing (EHV and HV) SCADA but with advanced functionality to facilitate timely and appropriate access to (and visualisation of) data, controls, operational systems such as distribution automation and active network management, alarms and indications for the LV network.

It has been estimated that £20,000 per HV/LV substation is an appropriate assumption for the CAPEX associated with the implementation of ACS functionality at LV. This includes CAPEX of £5,000 based on the procurement of a suitable RTU and the associated systems integration with LV monitoring, controlled devices and other operational systems. Such integration could be more onerous than it is today due to increased data exchange, model based standards and open standards communications protocols (e.g. IEC 61850). If an average of 4.5 feeders per HV/LV substation is assumed, then this converts to £4,444 per LV feeder.

It has been assumed that an OPEX rate of 10% is appropriate for an IT system of this nature, resulting in a total OPEX of £444 per LV feeder. Over a 15 year installed lifetime, this adds to £5,114 (taking present value at 3.5% discount rate).

5.1.1.2. Advanced Control Schemes at HV

The expansion of ACS to include HV could be viewed as more incremental a development than at LV. It is likely that some of the existing DNO infrastructure would be able to support the expansion of the network management system to include HV, although a number of new requirements are evident. These include the interaction and integration with active network management, distribution automation and commercial aggregators.

It has been estimated that £60,000 per EHV/HV substation is an appropriate assumption for the CAPEX associated with the implementation of ACS functionality at HV. This includes CAPEX of £5,000 based on the procurement of a suitable RTU, which may be deployed with dual redundancy, and the systems integration associated with HV monitoring, controlled devices and other operational systems. Such integration could be more onerous than it is today due to increased data exchange, model based standards and communications protocols (e.g. IEC 61850). This will also include the integration of multiple LV elements of the ACS with the HV element when required. If an average of 10 feeders per EHV/HV substation is assumed, then this converts to £6,000 per HV feeder.

It has been assumed that an OPEX rate of 10% is appropriate for an IT system of this nature, resulting in a total OPEX of £600 per HV feeder. Over a 15 year installed lifetime, this adds up to £6,910 (taking present value at 3.5% discount rate).

5.1.1.3. Advanced Control Schemes at EHV

In most cases, existing EHV networks have a more advanced associated SCADA infrastructure; while ACS implementation at EHV may be less complicated than at the lower voltages, the consequences of failure at EHV are higher due to larger loads and larger customer groups so that additional system resilience may be in order.

It has been estimated that £80,000 per GSP substation is an appropriate assumption for the CAPEX associated with the implementation of ACS functionality at EHV. This includes CAPEX of £5,000 based on the procurement of a suitable RTU, which may be deployed with dual redundancy, and the systems integration associated with HV monitoring, controlled devices and other operational systems. Such integration will be more onerous than it is today due to increased data exchange, model based standards and communications protocols (e.g. IEC 61850). This will also include the integration of multiple LV elements of the ACS with the HV element when required. If an average of 10 feeders per EHV/HV substation is assumed, then this converts to £8,000 per HV feeder.

It has been assumed that an OPEX rate of 10% is appropriate for an IT system of this nature, resulting in a total OPEX of £800 per EHV feeder. Over a 15 year installed lifetime, this adds to £9,214 (taking present value at 3.5% discount rate).

5.1.1.4. Cost curve for Advanced Control Schemes

It has been assumed that cost curve 2 is appropriate for control systems that are evolving to address increased complexity with 'early adopter' high pricing outweighing any cost savings due to Moore's Law (the expectation that IT systems deliver greater performance per unit cost over time).

5.1.2. Communications

Communications concern the aspects of data exchange where the focus is more upon the transmission, routing, and handling of lower level data packets rather than semantic or syntactic integrity (i.e. high-level message structures). We recommend that communications for smart grid / operational purposes is divided into three categories of 'enablers'. These are: Back-Haul, Fabric (i.e. Regional/Local) and Last Mile.

For the purposes of top-down modelling, it is important that DNOs are able to reflect their starting point including existing operational telecommunications and associated investments, together with planned future investments and technology preferences: these DNO-specific investments will also reflect some of the inherent aspects of communications in their territory with likely differences due to urban/rural and other geographic features. It is anticipated that the proposed set of three enablers (communications fabric, back-haul and last mile) can be utilised by each DNO to achieve this, including any revision of our initial estimates of parameters.

From our experience in utility communications systems, we have assumed an asset lifetime of 15 years which is likely to represent a mid-point for a lot of new communications devices. We have restricted our assumptions to one technology for communications fabric while each DNO will make its selection based on regional factors and earlier business decisions (sometimes referred to as 'inherent, inherited and incurred' factors).

5.1.2.1. Back-Haul

Back-haul infrastructure and services includes high-bandwidth, high capacity networks that are already in place serving multiple customers with a variety of voice and data requirements. The Smart Grid will build on the mature technologies and services that are already available, with a particular focus upon data security and integrity. Alternatively, private back-haul networks may already exist in some DNOs and these could/should be leveraged as there are initial sunk costs, - in this case, the costs attributable to Smart Grid traffic could be incorporated in the overall OPEX of such networks.

Minimum CAPEX assumption of £500 per communications device/node up to maximum CAPEX £100,000 per set of access/edge routers, i.e. dedicated IP/VPN, has been assumed. The rationale for these assumptions is outlined below.

- Minimum cost
    - Typical Industrial Firewall/VPN Router;

- Used to securely terminate a Back Haul Ethernet Wireline service to a boundary node such as smaller primary substation; and
- These devices can be added INCREMENTALLY on this basis as an additional element to an existing telecoms service agreement i.e. upgrading an existing high-speed link by an additional 2MBits/s.

- Maximum cost
  - Typical Ethernet Services Router, redundant hardware/multi-service;
  - Used as part of group of routers to create a secure, high speed, segregated network for operational data. Typically required to support multiple VPN Routing and Forwarding (VRF) instances as is standard practice in DNO WAN for SCADA, Corporate, Management, PMU over MPLS and/or SDH/PDH; and
  - These devices are unlikely to suit small-scale INCREMENTAL deployment because a fundamental set of equipment nodes and services will be required to facilitate ANY operational traffic carried over the DNO data traffic.

It has been assumed that OPEX will range from a minimum of £50 per annum to a maximum of £10,000 per annum. The rationale for these assumptions is outlined below.

- Minimum cost
  - Estimate of service and support charges on a bundled operational broadband contract; this figure represents an apportionment on a per feeder basis.
- Maximum cost
  - Estimate of service and support charges on a typical ISP dedicated access contract – approx. 100Mbits/sec from SGS experience of recent similar projects in GB.

5.1.2.2. Regional/Local Fabric Communications

The Regional/localised communications fabric enabler is focused on the operational data traffic that will be required for many of the enablers and solutions in TRANSFORM. We anticipate that this does not yet exist in most DNOs, or exist in the form required that satisfies reliability, diversity and security metrics. The build out of this fabric will require the most inventive solutions, on an as needed basis, that supports the grid management applications being put in place and devices being deployed. Greater variety in the form of technologies, approaches, vendors and integration issues prevail in this space and as such greater cost must be factored into the model to take account of this.

It has been assumed that CAPEX will range from a minimum cost of £500 per communications device/node up to a maximum cost of £500,000 per regional integrated communications system (i.e. scanning telemetry system). The rationale for these assumptions is outlined below.

- Minimum cost
  - Typical Radio Modem
  - Used to provide wireless connectivity between 2 or more remote devices at distances up to 5km.
  - Can be added incrementally on this basis as additional nodes on a local or regional basis.
- Maximum cost

  - Assuming up to 100 outstations including RTU/Comms capability/Field integration, Antenna (if required) Central Master Station/Controller and associated licensing;
  - Used to provide wireless connectivity between 2 or more remote devices at distances up to 50km – includes Field I/O, limited programmability, network management functions for Fabric, ingress/egress data gateways; and
  - Initial install not considered incremental – but on-going extension/expansion as regional footprint increases may be implemented incrementally.

It has been assumed that OPEX will range from a minimum of £50 per annum to a maximum of £50,000 per annum. The rationale for these assumptions is outlined below.

- Minimum cost
  - Estimate of support charges on maintenance agreement from vendor; this figure represents an apportionment on a per feeder basis.
- Maximum cost
  - Estimate of service and support charges on a typical vendor support contract for a system of up to 100 outstations.

5.1.2.3. Communications – Last Mile

Last mile communications requirements are particularly relevant in remote sensor data capture. Last mile includes low-cost, mass-produced devices that leverage existing technologies, protocols and fixed carrier infrastructure such as ADSL (Asymmetric Digital Subscriber Line) or POTS (Plain Old Telephone System). Emerging technologies such as BPL (Broadband over Power Line) and/or PLC (Power Line Communications) from the secondary substation to downstream devices may become economically feasible in the short/near term. It is possible that last mile services may be offered by the Communications Service Provider under DECC's DCC initiative, provided that these services can be made available at market prices and meet operational requirements.

Initial CAPEX assumptions have been made, ranging from a minimum cost of <£100 per communications device/node up to maximum cost of £50,000 per district integrated communications system, i.e. BPL system with gateway to higher-level fabric/back-haul.

- Minimum cost
  - Typical Industrial Terminal Cabinet Kit;
  - Used to provide wireless connectivity between remote devices installed at LV location at distances up to 10km from Cellular Base Station; and
  - Can be added incrementally on this basis as additional nodes on a local basis.
- Maximum cost
  - We have not been able to identify a suitable price point here and have made an 'heroic assumption' for maximum costs;
  - Used to provide powerline carrier connectivity in a hub/spoke configuration between 2 or more remote devices and a primary/secondary DNO substation at distances up to 5km; and
  - Initial install not considered incremental, additional BPL modems at end points could be considered incremental – economies of scale would apply in the procurement and installation of these devices.

It has been assumed that OPEX will range from a minimum of £10 per annum to a maximum of £5,000 per annum. The rationale for these assumptions is outlined below.

- Minimum cost
  - 10MB on any network - £7/month + 1 off charge;
  - Source: Research on 3G/GPRS data charges; and
  - Estimate of data charges on annual contract from service provider vendor; this figure represents an apportionment on a per feeder basis.
- Maximum cost
  - Again we are unable to identify a suitable price point here and have made an 'heroic assumption' for maximum costs; and
  - Maximum cost needs to reflect lack of 3G/GPRS in many regions of GB at present.

5.1.2.4. Cost curve and asset lives for communications

For each of the communications variants, it has been assumed that cost curve 3 is appropriate for use. An asset lifetime of 10 years is representative of communications hardware; it may however be appropriate to select a lower asset lifetime to reflect communications obsolescence and change-out rates. In line with discussions at WS3 meetings, we have assumed a 15-year asset life which is comparable to similar devices deployed in DNOs, e.g. protection relays.

5.1.3. Design Tools

Existing network planning methods make use of software packages provided by specialist vendors that are focused on steady state and dynamic simulation of the power system to explore performance issues and various phenomena. These tools work on the basis of a core set of models representing the power system and its various components. There is a range of functionality and capability across the various products on the market. At the present time, the tools utilised by DNOs usually involve the manual preparation and maintenance of the power system model and any associated data, plus the manual building and running of a range of scenarios driven by industry planning standards, e.g. P2/6. These tools are provided on a per user or desk basis and require specialist training in power systems analysis to operate them and interpret the results.

In the future, the expansion of LCTs and the increase in size of the network model will pose several challenges to existing planning teams and the tools they use. There will be an increasing need to consider, inter-alia, snap-shots and time-series or probabilistic based analysis of new technologies and operational schemes at the planning stage, including but not limited to:

- Demand response;
- Active network management solutions;
- Distribution automation schemes;
- Power electronics based devices;
- Real-time ratings calculations;
- Electrical energy storage; and
- Thermal energy storage.

In addition, the introduction of new commercial arrangements and services will further complicate the generation, running and reporting of planning scenarios. It will be particularly important that the design tools have easy access to earlier deployed schemes, such as demand response solutions, in order to avoid any risk of 'double counting' or not accurately treating any novel solution. This will likely rely on coordination of IT systems and has been addressed in our note and enabler that is intended to cover data architecture and management.

At the present time, the planning tools enabler is included as a single £10,000 CAPEX allocation that can be selected a number of times for top-down modelling. It is recommended that this amount be doubled to £20,000 to reflect the need to address increasing scale and complexity. Each DNO should select a multiple of this enabler based on the estimated number of planning engineers required. It is recommended that existing investments in tools/techniques should not be counted against this figure. Costs associated with supporting IT, data management, access and security will be included within the Holistic Data Management enabler.

It is recommended that an initial estimate of OPEX of 10% is used, resulting in £2,000 per annum. As the complexity of the tools increases this OPEX could increase, it is suggested that this is reviewed as more information comes to light. There will also be a corresponding increase in a requirement for training of planners to use these advanced tools and learn new skills, e.g. software scripting to drive simulations, this has not been taken account of at present. It has been assumed that the lifetime for this enabler is 15 years.

5.1.3.1. Cost Curve for Design Tools

It has been assumed that cost curve 2 should be used for Design Tools. This is due to the uncertainty around the expansion of these tools to embrace more technologies and more complexity, which could offset any reduction in cost on proven capability.

5.1.4. Distribution State Estimation

While there are some early signs of pseudo-state estimation by interpolation of SCADA data (such as optional modules provided by SCADA vendors), we are not yet aware of any market-ready DSE solutions. This is reflected in our assumptions and estimates, as detailed in the following sub-sections.

It is anticipated that Distribution State Estimation (DSE) systems are likely to be software-based and licensed on a per tag basis, in a similar manner to Distribution Management Systems and Data Historians. These tags can be measurement and status inputs to the DSE, and outputs, i.e. values derived by the DSE.

We have estimated that the DSE licensing costs will be in the region of £10 per tag, although wider rollout of DSE may reduce those costs. This estimate is based on our understanding of data historian tag costs. Tags include:

- Measured Voltage (if available);
- Measured Current (if available);
- Measured Power Flow (if available);
- Pseudo-measurements (if required);
- State variables (Voltage magnitude and angle derived by the DSE);
- Derived quantities and corrected measurements (P, Q and I); and
- Derived error bounds/confidence intervals on estimates (upper and lower bounds).

For an EHV/HV feeder, it has been assumed that 1-10 tags will be required for input data. It should be noted that network topology and existing measurements will influence the number of pseudo-measurements required. To describe the system state for a feeder will require approximately 18-25 tags. These include: state variables (Voltage magnitude and angle at every bus), corrected values for measured values; corrected values for all pseudo-measurements, all values derived from the state variables which are not measurements (Active Power Flows, Reactive Power Flows and Current) and upper and lower bounds for the estimate of error in all of the above.

Based on 30 tags per feeder and an assumption of a licensing cost of £10 per tag, it is assumed the total licensing cost will be in the region of £300 per feeder. While this is likely to be an annual recurring cost, it is included in our overall estimate of 10% OPEX.

In addition to the above need for DSE tag licences there will be a capital cost in establishing DSE functionality, involving the following activities, with comments on likely costs.

Table 10: Activities associated with DSE and accompanying commentary

Activity	**Comments**
Procurement/Installation of appropriate IT hardware/software,	It is expected that DSE would be deployed and made available for most/all of a DNO network (this would help ensure a 'no regrets' approach to smart enablers/ solutions). A suitable DSE deployment may cost £2.5M per DNO which would represent about £180 CAPEX/LV feeder and £5500/HV feeder if deployed on 5% of feeders
Creation/population of DSE model on software platform	
Testing/configuration/commissioning of DSE model	

Table 11: CAPEX assumptions for DSE at LV and HV

Estimated cost of DSE for DNO	£2,500,000
LV Feeders (average per DNO from GB data)	69,000
HV Feeders (average, as above)	2300
Assume 50/50 split between LV/HV	£1,250,000
Assume 10% feeders use DSE	
No of LV Feeders	6900
No of HV Feeders	230
Per Feeder CAPEX LV	**£180**
Per Feeder CAPEX HV	**£5500**

5.1.4.1. Cost Curve for DSE

Cost curve 3 has been selected as DSE is not expected to deliver a commodity-based solution to this problem, so costs will not dramatically reduce but are expected to moderate.

5.1.5. Data Management

Data Management concerns the aspects of data exchange, usage, meaning and structure that will enable operational Smart Grid applications and systems to support the demands of LCTs using existing networks so far as practicable.

5.1.5.1. CAPEX

We consider that the costs of ensuring appropriate data management will be similar to those involved in providing regional/local communications fabric functionality. This will be dependent on a number of factors and potential economies of scale associated with a top-down deployment. Initially, we have assumed the per feeder cost of this to be £10,000. This will benefit from further review and revision based on DNO experience and LCNF project learning.

These indicative figures are derived from first hand practical experience in the GB industry. In these earlier cases, an organisational function/unit was created to handle Data Architecture and Management. Estimates of the costs of the tools and training required is given for initial establishment of a Smart Grid Data Organisational Unit within a UK DNO; this unit would be responsible for the collection, storage, management and dissemination of Smart Grid data at both operational and back-office/corporate level. The organisation unit should include responsibility for facilitating and managing data exchange associated with but not limited to Demand Response, Distributed Generation, ANM, Fault and Alarm Management, Measurement Validation and Network Observability/Visibility. It is likely that these requirements and responsibilities will evolve and grow incrementally and the estimates have reflected this as far as possible.

5.1.5.2. OPEX

As per our approach to OPEX noted earlier, we expect that an annual rate of 10% is appropriate.

The operational expenditure represents an estimate of the FTE costs for personnel and support/licensing for the tools/training needed to keep the function active and relevant across the business.

Following the incremental development approach mentioned above, the incremental costs represent the addition of functional specialism on a subject area basis; the estimate is equivalent to adding a FTE to an existing organisational function, and is again based on first-hand experience in the GB energy industry.

5.1.5.3. Cost Allocation

The TRANSFORM model applies costs on a per-feeder basis while we recommend that the Data Management Enabler be applied as a per-DNO investment in advance of the deployment of smart enablers and solutions as part of a top-down strategy. Therefore, each DNO must determine the level of investment required – numbers provided here are reasonable assumptions but do not reflect the different starting positions of DNOs.

5.1.5.4. Investment Profile

The time taken to establish an appropriate Organisation Unit, and to ensure that Smart Grid data is properly collected and available for smart solutions, will extend to a number of years. We recommend that the investment is assumed to require between three and five years of start-up prior to any solution deployments.

5.1.6. LV Consolidated Monitoring

This enabler consolidates a number of different LV monitoring functions in earlier iterations of the TRANSFORM model: LV phase imbalance; waveform monitoring; feeder monitoring and transformer monitoring. Many of these monitoring functions will share instrumentation and use very similar if not identical data acquisition hardware. Hence these functions have been consolidated into one function for top-down rollout.

It has been assumed that the lifetime of the first generation of LV monitoring equipment will be on a par with other monitoring solutions current deployed within the electrical industry at approximately 15 years.

DNOs have already demonstrated live installation methods for LV monitoring, so a disruption factor of zero is assumed. Flexibility of monitoring equipment is set at 3, as it could be redeployed on different feeders, incurring additional OPEX.

The use of this enabler/solution would replace the following enablers:

- Phase Imbalance LV
- Phase Imbalance HV
- Waveform Monitoring LV
- Waveform Monitoring HV
- Waveform Monitoring HV 2 (Feeder)
- LV Feeder Monitoring
- LV Feeder Monitoring 2 (Distribution Substation)
- HV/LV Transformer Monitoring

5.1.6.1. CAPEX

It is expected that the first generation of devices will require CAPEX of £2000-£3000 plus installation costs (2 hours on site). It is assumed that economies of scale and efficiencies in the design of LV monitoring devices will reduce cost to the £500 per unit level if rollout becomes wide-spread. Different form factors may be required for types of installation, i.e. ground mounted substations or pole-mounted transformers.

5.1.6.2. OPEX

OPEX has been assumed to be 4% as per recent WS3 discussions.

5.1.6.3. Cost Curve

Cost curve 4 is appropriate for this enabler. Cost curve 4 is selected "*where volumes are expected to be moderate (e.g. HV or LV network solutions)*".

5.2. Solutions

5.2.1. Generator Side Response

At the present time in the existing TRANSFORM model, Generator Side Response (GSR) is included as variants across LV, HV and EHV plus a distinction is made between operating in PV or PQ mode. PV mode could involve the regulation of real and/or reactive power to maintain the voltage (to the extent possible) at the point of connection to the network within a specific limit. PQ mode involves the operation of the generator at a pre-defined power factor, with the relationship between real and reactive power fixed and not altered in response to the network voltage at the point of connection.

It is recommended that in the future, WS3 considers whether the distinction between PV and PQ mode is necessary in the context of the design and use of the TRANSFORM model. The ability of GSR to contribute to thermal or voltage headroom is site specific and will be delivered through the control of real and/or reactive power output at the generator; we expect that the DNO will determine PV or PQ operating mode as a part of any GSR engagement. The type of generator will be the main factor in whether GSR can release headroom and/or legroom. For example, a wind farm cannot reliably increase output in the way that a CCGT can, but both could be candidates for GSR. There are also varying degrees of controllability of real and reactive power at generators of different sizes.

We note that the existing GSR solutions are tailored for application to existing generators, rather than for future or prospective connections to the network. We expect that the costs and assumptions made are not directly applicable to future connections. This is because the focus on payments to generators for services is heavily influenced by LCNF project learning to date, and does not reflect the payments, costs and possible changes to use of system charging that could be implemented for new connections or non-aggregated generators, particularly when the GSR service being implemented reduces connection costs and timescales for the developer. The costs associated with service provision are included as OPEX costs.

We have anticipated that each of the GSR solutions will require communications and data enablers in order to function. We have aimed to ensure that the additional operating costs such as system planning are also included in any OPEX assumptions.

5.2.1.1. GSR at LV

We recommend voltage and thermal headroom values are set to +/- 3% for volts and 10% for thermal headroom.

5.2.1.2. GSR at HV

As with GSR at LV, we recommend that voltage and thermal headroom values need to change - +/- 3% for volts and 10% for thermal headroom.

5.2.1.3. GSR at EHV

We anticipate that EHV systems may be able to accommodate larger variations in Voltage and loads in many cases, particularly where there are no directly-connected customers; for this reason, we recommend that voltage and thermal headroom values be set to +/- 5% for volts and 10% for thermal headroom.

5.2.2. Active Network Management

It is anticipated that Active Network Management (ANM) systems will be software-based, hosted on field-based RTU, commodity server or similar platforms and licensed on a per-tag basis in a similar way to traditional SCADA and data historian packages. These tags will be inputs, i.e. measurements and status indications to the ANM system and outputs, i.e. control instructions derived and implemented by the ANM system. It is envisaged that ANM will perform autonomous control and coordination of devices to maintain the distribution network within voltage and thermal limits. The number of tags required will be related to the size of the network area where ANM is being applied and the number of controlled devices included within the scope of the ANM scheme.

5.2.2.1. ANM at LV

We have attempted to estimate high- and low-CAPEX costs for the hardware/software necessary to provide ANM functionality. The high-CAPEX solution is expected to be capable of controlling up to 10 LV feeders while the low-CAPEX solution can control two feeders. It should be noted that there are no such deployments of ANM at LV at the present time.

For a high-CAPEX solution, we have assumed a compact RTU-industrial controller plus accompanying hardware/software capable of active management at 10 LV feeders, at a CAPEX cost of £40,000.

For a low-CAPEX solution, it is anticipated that future product development will lead to convergence of LV monitoring functionality (from our LV monitoring assumptions) with that required for ANM at LV substations. In anticipation of this convergence and acknowledging that LV ANM will initially be limited in deployment we have assumed a CAPEX cost of £4000 per LV substation for hardware and associated ANM software. We have also assumed that a maximum of two feeders will require LV ANM at any LV substation. Each feeder is anticipated to involve two controlled devices.

In each case, an ANM device or software function at each controlled device is estimated at £500 per unit, with an assumption of two devices per feeder.

Adding these gives a total CAPEX for 2 LV feeders of about £4000 + £2000 = £6000.

Pro-rata, the Low-CAPEX estimate for one LV feeder is therefore £3000. However it is more realistic to assume that in some circumstances, only one feeder will require ANM so that the low-CAPEX per-feeder cost is £4000 +£1000, or £5000.

In comparison the high-CAPEX solution would cost £40,000 + £10,000 to support 4.5 feeders – a per feeder cost of £11,111.

ANM at LV will be dependent on the selection of other enablers in the form of planning tools and communications across back-haul, fabric and last-mile. In practice there will be differences in CAPEX/OPEX ratios due to the use of either in-house DNO communications or bought-in.

We have assumed a lifetime of 15 years for the ANM system. Assuming 10% OPEX for the provision of a software-based solution and additional associated operating costs, this gives an OPEX of £500 per LV feeder per year.

5.2.2.2. ANM at HV/EHV

It is envisaged that ANM at HV and EHV will be relatively similar in terms of devices, systems and costs but will be different in terms of solution benefits. ANM at EHV/HV has already been implemented in the UK but is not yet widely adopted. In some existing deployments (e.g. the Orkney Isles), devices at HV are actively managed to remove constraints at EHV.

We have assumed CAPEX for up to 10 EHV or HV feeders of £125,000. As with LV ANM, above, this estimate is based on typical costs for suitable commodity servers and/or other computing platforms with the necessary processing power, software hosting capability and multiple communications protocol support required to perform this function. Naturally, with larger loads and customer groups associated with EHV and HV schemes than at LV, we anticipate multiple redundant hardware/software configurations will be required and our estimates include for this. We have also included an estimate of the additional software and systems integration activities associated with ANM deployment (set-up, configuration and testing).

An ANM device or software function at each controlled device is estimated at £5,000 per unit, with an assumption of one device per feeder.

Our estimate for the CAPEX associated with this device includes an estimate of the cost of systems integration, ANM software plus configuration and testing of each device.

Total CAPEX for 10 HV or EHV feeders is £130,000. Therefore, ANM per EHV or HV feeder CAPEX is estimated at £13,000.

We have assumed a lifetime of 15 years for the ANM system and an annual OPEX rate of 10%.

5.2.2.3. Cost Curve for ANM

We have reviewed the use of cost curves as reported in the Phase 2 report. In each case, we have left the cost curve assumptions at curve 2 (i.e. flat cost profile over time). This is because we anticipate that, despite the likely effects of Moore's Law in reducing IT-based hardware costs, future software licence fees may rise to absorb any reduction until we see signs of market maturity at some later date; at present, we expect that the market is dominated by 'early adopters'.

5.2.3. Real Time Thermal Ratings for Overhead Lines

Real Time Thermal Ratings (RTTR) relates to the use of meteorological information in order to derive constantly varying estimates of the current carrying capacity of any individual circuit. The original RTTR entries assumed a software based estimation algorithm utilising weather station data but with no direct measurement validation. The experience of SGS suggests that in order to have confidence in the RTTR estimates a limited number of direct measurements are desirable in order to reduce the error associated with the estimate. This recognises the safety critical aspect of ratings and why they are applied in order to ensure ground clearance.

5.2.3.1. RTTR at LV OHL

When considering RTTR for LV circuits, we are aware that most of the existing LV circuits are operated unmonitored on a 'run to fail' basis. This has been a valid operating approach for traditional LV demands, where for example domestic peak demands have declined (ADMD has changed from about 2.5kVA/customer to about 1.7kVA/customer – itself probably due to changes away from low efficiency domestic appliances together with some evidence of price elasticity). However, the introduction of LCT will not allow this practice to continue without severely impacting customer service standards, with consequential financial implications for DNOs.

We are aware that some DNOs are trialling IFI projects focussed on LV RTTR and for this reason, we recommend that the model reflects the likely long delay before any widespread deployment is carried out – this can be done by setting LV RTTR solution 'Year Solution Becomes Available' to 2020 or 2025.

We have estimated that the CAPEX would include:

- Conductor temperature monitors on key spans along each feeder; and
- Software installation, configuration and testing to derive estimates for each span along a feeder.

It has been assumed that a small number of conductor temperature monitors is required based on the locality of the feeders. At LV the meteorological conditions are unlikely to be materially different from one feeder to the next. We have assumed up to 10 LV feeders for 1 secondary substation. The conductor temperature monitor would be installed on 3 critical spans across the 10 feeders and will provide data back to the RTTR estimation algorithms to derive RTTR values for all spans across the 10 feeders taking account of topology and asset information. CAPEX cost for one feeder for conductor temperature monitors has been estimated at £900.

Software will also require to be installed either centrally or at the secondary substation in order to execute the algorithms to generate the RTTR estimates. Similar to other software applications such as Distribution State Estimation this software will likely be limited on a per tags basis. It is expected that this software would be deployed through on an existing or model selected hardware Enabler (e.g. ANM for LV or SCADA server). This would allow the user to decide how to configure the application and what data the application will use (hence represent how complex). Metadata will include conductor and topography information. Input tags would include meteorological data and conductor monitoring for each span. Output tags will include RTTR and error estimates for each span. It is estimated there will be 10 input tags, 5 output tags and 30 spans per LV feeder and this is rounded up to a total of 500 tags per feeder. At a cost of £5 per tag the cost per feeder is estimated to be £2500.

Total CAPEX per feeder is £900 (conductor temperature monitors) plus £2,500 (RTTR software application) = £3400 per feeder.

Annual OPEX is set at 10% of CAPEX and we anticipate that this would represent conductor temperature monitor checking and maintenance, data management and support for the RTTR software configuration. Annual OPEX charge has been estimated at £340.

5.2.3.2. RTTR at HV OHL

We have estimated that the CAPEX to deploy RTTR at HV would include:

- Conductor temperature monitors on key spans along each feeder; and
- Software installation, configuration and testing to derive estimates for each span along a feeder.

It has been assumed that a larger number of conductor temperature monitors is required than at LV as the circuits will be more geographically dispersed. At HV the meteorological conditions are therefore more likely to be different from one feeder to the next.

We have assumed 6 HV feeders for 1 primary substation. We have assumed that one conductor temperature monitor would be installed on a critical span of each feeder and will provide data back to the RTTR estimation algorithms to derive RTTR values for all spans across the 6 HV feeders taking account of topology and asset information. Therefore, 6 conductor temperature monitors suitable for HV circuits would be required for 6 feeders (equivalent to 100% of feeders having a device installed). Devices available on the market have very different costs therefore SGS has assumed a broadly central cost of £10,000 per device. CAPEX cost for one feeder for conductor temperature monitors would therefore be £10,000.

Software will also require to be installed either centrally or at the secondary substation in order to execute the algorithms to generate the RTTR estimates. Similar to other software applications such as Distribution State Estimation this software will likely be limited on a per tags basis. It is expected that this software would be deployed through on an existing or model selected hardware Enabler (e.g. ANM for LV or SCADA server). This would allow the user to decide how to configure the application and what data the application will use (hence represent how complex). Metadata will include conductor and topography information. Input tags would include meteorological data and conductor monitoring for each span. Output tags will include RTTR and error estimates for each span. It is estimated there will be 10 input tags, 5 output tags and 50 spans per HV feeder totalling ~750 tags per feeder. At a cost of £5 per tag the cost per feeder is estimated to be £3750.

Total CAPEX per feeder is £10,000 (conductor temperature monitors) plus £3,750 (RTTR software application) = £13,750 per feeder.

Annual OPEX is estimated to be around 10% of CAPEX, which would include conductor temperature monitor checking and maintenance, data management and support for the RTTR software configuration. Annual OPEX is therefore estimated at £1380.

5.2.3.3. RTTR at EHV OHL

We have estimated that the CAPEX to deploy RTTR at EHV would include:

- Conductor temperature monitors on key spans along each feeder, or higher cost modelling software as a substitute; and
- Software installation, configuration and testing to derive estimates for each span along a feeder.

We have assumed four EHV feeders for one Bulk Supply Point. We have assumed that one conductor temperature monitor would be installed on a critical span of each feeder and will provide data back to the RTTR estimation algorithms to derive RTTR values for all spans across the four EHV feeders taking account of topology and asset information. Therefore, four conductor temperature monitors suitable for EHV circuits would be required for four feeders (equivalent to 100% of feeders having a device installed). We have reviewed the cost of typical devices targeted at transmission circuits and we have assumed a cost of £20,000 per device. CAPEX cost for one feeder for conductor temperature monitors would therefore be £20,000.

Software will also require to be installed either centrally or at the secondary substation in order to execute the algorithms to generate the RTTR estimates. Similar to other software applications such as Distribution State Estimation this software will likely be limited on a per tags basis. It is expected that this software would be deployed through on an existing or model selected hardware Enabler (e.g. ANM for LV or SCADA server). This would allow the user to decide how to configure the application and what data the application will use (hence represent how complex). Metadata will include conductor and topography information. Input tags would include meteorological data and conductor monitoring for each span. Output tags will include RTTR and error estimates for each span. It is estimated there will be 10 input tags, 5 output tags and 50 spans per EHV feeder totalling ~750 tags per feeder. At a cost of £5 per tag the cost per feeder is estimated to be £3,750.

Total CAPEX per feeder is £20,000 (conductor temperature monitors) plus £3750 (RTTR software application) = £23,750 per feeder.

Annual OPEX is estimated to be around 10% of CAPEX to cover temperature monitor checking and maintenance, data management and support for the RTTR software configuration. OPEX is therefore estimated to be £2,375.

6. CONCLUSIONS

SGS has completed a review of the solutions and enablers currently listed in EATL's TRANSFORM econometric model of long-term costs associated with the anticipated introduction of Low Carbon Technologies in GB. This review has also highlighted several new enablers/solutions that were previously not included within the model.

SGS anticipates that the revised cost estimates are likely to cause an overall increase in TRANSFORM model output costs, which will be determined in due course by EATL.

The model and the associated data set should be subject to continual review and revision, particularly when IFI and LCNF project results provide suitable data on costs and performance of new technologies. It is expected that this will be facilitated through the existing governance process.

7. APPENDIX A – USEFUL REFERENCES

- Estimating the Costs and Benefits of the Smart Grid, EPRI Technical Report, March 2011
- Long term capital expenditure forecasts for the electricity networks in great Britain, SKM for ENA, July 2007
- Electricity Distribution Price Control Review, Final Proposals, OFGEM, November 2004
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