

Treatment of Existing DG Connections from 2010

Introduction

Prior to the Implementation Steering Group (ISG) on 25 April 2006, Ofgem produced a discussion note for ISG members on generator charging from 2010. The note was discussed at that meeting and Ofgem then requested further specific details from DNOs about existing distributed generation (DG) connected to their systems. We have already provided, as best we can, the specific information requested in the discussion paper and in follow-up e-mails. This paper provides SSE's views on the substantive issues raised in the ISG paper.

We comment firstly on Ofgem's discussion of the objectives for the review of the position of existing DG and then consider the options that are put forward in the paper. This includes a detailed analysis of option c2), which appears to be Ofgem's favoured approach in the ISG paper. We conclude that this option is impracticable and that option a) represents the best way forward, considering the objectives for a solution to the issue of existing DG.

Background

As Ofgem are aware, SSE is extremely concerned about proposals to bring long-standing existing DG within the charging base for distribution use of system charges. Such DG connected under an entirely different commercial and regulatory regime. The introduction of use of system charges could undermine the profitability of such generation and could even jeopardise their commercial viability. As Ofgem has acknowledged in the paper, legal issues associated with property rights are raised with the potential introduction of generator distribution use of system charges (GDUoS) for existing DG. Such a move would send a perverse signal about the regulatory risk of generation investment to the investment community at a time when government policy seeks to maximise the availability of new, and particularly renewable, generation. It would also be inconsistent with Ofgem's objective, set out in its most recent corporate strategy and plan, to promote stability and certainty in the generation market. We therefore consider that introducing GDUoS for existing DG would be inconsistent with DNOs' general obligation to facilitate competition in generation and supply.

We believe there are specific issues about the introduction of a revised approach for distribution use of system charging in the north of Scotland and this is discussed further in Appendix 1 to this note.

Discussion of Objectives in Ofgem's paper

In section 2 of the paper, Ofgem discusses a number of policy objectives as well as a set of objectives for a solution to the issue of pre-existing DG. We discuss each of these sets of objectives in turn.

Policy Objectives for Charging DG

We are encouraged to note, in relation to the policy objectives, that Ofgem recognises the issue of the property rights of existing DG. This, together with consideration of the effect of any solution on perceptions of investment and regulatory risk in the generation market, is an

important factor in determining an equitable way forward. The practicability and implementation costs of any approach are also important – bearing in mind Ofgem’s duty to have regard to the principles of better regulation.

Taking a step back, it is ultimately customers who pay for all elements of the electricity value chain that leads to the provision of their supply, including the generation costs. In one sense, it is artificial to divide network infrastructure charges between generation and demand, as the demand side will pay both elements anyway. In a distribution network system there is, in our view, no unambiguous way to determine exactly what “costs” any particular demand, generation or combined site imposes on the network.

Against this background it is, in our view, disproportionate regulation to require DNOs to develop complex use of system charges for the DG sector in the future. Going further than this, and requiring application of use of system charges to existing DG not only brings unnecessary uncertainties and risks to the DG market as we have noted above, but we believe there could also be a significant risk of unintended consequences. For example, in the north of Scotland, if the established DG was forced to exit from the market, there would be a risk of stranded assets and potentially the need for reinforcement elsewhere in the system to cater for the different power flows then needed.

Ofgem discusses the influence of GDUoS charges on generator siting, usage and decommissioning decisions. Existing DG cannot change their siting decisions, which were made in a completely different commercial environment. Decommissioning of existing DG would run counter to current government policy to promote the growth of such generation. It appears possible that there might be other ways of influencing DG usage decisions, as discussed in the document in relation to option a). In our view, there would be merit in exploring these measures in relation to existing DG rather than pursuing the application of GDUoS for the reasons described above.

Objectives for a Solution

Ofgem’s objectives, in summary, are that the solution to the issue of pre-existing DG is:

- Simple and transparent;
- Proportional and minimises regulatory risk;
- Delivers best result for customers;
- Non-discriminatory between existing and new DG.

We agree with the first three of these but have some concerns over the interpretation of the fourth. In our view, it would not be discriminatory to treat DG differently where it connected under different circumstances.

In terms of the objectives for a solution, we believe that it may not be possible to satisfy all of these to the same extent and that Ofgem may have to consider the “best fit” between the various options and the listed objectives.

Options in Ofgem's paper

Option a) "do nothing"

This option entails no introduction of charges for pre-existing DG and we believe that this is the best fit against Ofgem's objectives. It is simple and transparent and it does not raise issues of regulatory risk as only DG connected from 1 April 2005 in a framework that clearly included GDUoS charges would be affected by these charges. We believe it will also be good for customers as it avoids any increased perception of regulatory risk in the generation sector feeding through to increased prices seen by end-customers. In our view, this option is not discriminatory as it recognises that existing DG made investment decisions in a different commercial framework that did not include GDUoS.

There may be some merit in Ofgem's proposals for DNOs to contract with DG not to run at certain times in order to avoid the need for distribution network reinforcement. This option is likely to entail the development of a constraint payment mechanism, which would take some time and effort to develop. However, it may represent a means by which DNOs could build up a case for distribution reinforcement when this is economically justified. The costs of developing such a system may well represent a more justifiable method of introducing economic considerations into generator-related distribution investment than complex GDUoS charging methodologies. A further benefit would be the promotion of stability and certainty in the generation market, which Ofgem states, in the most recent corporate strategy and plan document, that it is working with Government to provide.

Under this option, Ofgem discusses the question of further contribution by DG to the "joint use" assets that were required to be installed when the connection was originally established. In our view, this is simply not practicable. The concept of sole-use and joint-use assets has only been developed in regulatory thinking relatively recently. There has been no requirement over the years to establish and record this boundary between asset types needed at the time of connection. To try to do so retrospectively for any connection would be difficult, time-consuming and open to challenge by interested parties. We discuss this in further detail in our assessment of option c2) below.

Option b) introduce GDUoS with no compensation for deep connection charges

This option will clearly be unacceptable to the generation community who own existing generation due to the financial penalties that the ex-post introduction of GDUoS charges would represent. Introducing such charges for existing DG would undermine their property rights, as Ofgem acknowledge. The option takes no account of any funding towards network infrastructure that would already have been provided by existing generators through the deep connection charge policy. It is also inconsistent with the precedent set in transmission where generators have been given a rebate for previously incurred costs when connection boundaries have changed.

Option c) introduce GDUoS with compensation for deep charges paid

There are two variations on this option set out in Ofgem's paper. Option c1) links compensation to the value of the current access right while option c2) compensates DG for the change in connection boundary from deep to the recent "shallowish" level.

In our view, whilst option c2) follows the logic of the compensation awarded to connected parties when transmission connection boundaries have changed, it is completely impracticable at distribution level, as we discuss in more detail below. Option c1) also presents some

practical difficulties and does not remove the prospect of additional financial burden on existing DG if GDUoS charges increase over time. It therefore has similar characteristics to option b) and is similarly unacceptable.

Issues with Option c2)

In Ofgem's overview of this option, it is described as "compensating pre-existing generators for the change in the connection charging boundary in either a one-off or an annuity payment" with the accompanying step of then also charging the prevailing rate of GDUoS going forward. We consider the practical issues with this approach below but firstly comment on the scope of connections that Ofgem consider would be covered by this exercise.

It is suggested in the paper that "generators connecting prior to 1990 would not be considered for compensation" due to the likely financing period for DG connections being some 20 years. While this sort of timescale may be appropriate for some types of DG technology, it is emphatically not the case for the long-lived hydro-electric generation assets. Appendix 1 discusses the history of development of hydro generation in the north of Scotland and the long-lived assets that were created for the purpose of generating electricity. We strongly believe that any work to develop compensation for existing DG under this option would have to include the hydro generation assets. The suggested cut-off also does not recognise when other types of DG might have refurbished their own generating assets on the expectation of further years of export potential on the original terms of connection.

For a practical analysis of issues with this option, it is worthwhile considering what steps a DNO would actually need to take for each pre-existing DG connected before a certain date, in order to consider what resource would be necessary to implement this option. We have made an attempt at this in Appendix 2 to this note and arrived at indicative figures of 2 and 3 man-years of engineering effort alone for SHEPD and SEPD areas respectively. Across all the DNOs, this would equate to some 35 man years of effort and still not cover all the work required. There would then be the commercial time required for customer discussions to be considered and for this aspect of costs, we have some experience to draw on.

Uniquely amongst the DNOs, the Scottish companies have had some experience of this sort of exercise due to the transmission connection charging boundary changing in Scotland as part of the arrangements for the introduction of BETTA. In the case of SHETL, 6 sites were to be compensated for the change in boundary. At transmission level, due to the size and value of the assets involved in making connections, there was some information about the assets employed, in contrast to that available for the lower value distribution-level connections. Despite this, it has been a time-consuming process for SHETL staff with the customers concerned querying all aspects of the process by which the compensation amounts were calculated including:

- Determination of the infrastructure and connection boundary;
- Disaggregation and valuation of assets;
- Methodology for depreciation and indexation adjustments;
- allocations of shared costs such as wayleaves and civil works.

In a number of cases, customers have found it worthwhile to engage consultants, who then sought to maximise the compensation value on their behalf, thereby considerably extending

the time needed by SHETL staff to answer queries and defend the approach that had been taken. In elapsed time, the whole process has taken over a year, with some of the connectees intimating to us that they still may refer the matter to Ofgem for determination. It is highly probably that at least some existing DG connections would take a similar approach if this option were to be pursued.

Clearly, the difference in scale between 6 transmission connections and the hundreds of existing DG sites suggests that considerably more effort would be needed by SSE distribution staff to deal with customers' queries and concerns about the approach being used should option c2) be progressed. There are also other considerations:

- The significant engineering resource required for this exercise would have to be fitted around other engineering workload and would therefore take considerably longer in terms of elapsed time. It would not be possible to outsource this work as personal knowledge of the system and connections history would be required.
- The distribution system changes more quickly than the more static nature of the transmission system making the determination of exactly what assets were added by a particular connection less certain as you look further back in time.
- Loading details for the hypothesised system at the time of the DG connection, required to ascertain the connection charge under the "shallowish" policy, would have to be estimated and could be subject to challenge.
- There may be legal issues associated with how compensation will be awarded where there has been a change in ownership of the connection site under consideration since the original connection charge was paid. This will be further complicated for those sites where there have been infrastructure upgrades at different times as connection requirements have changed.
- A comprehensive exercise to re-establish connection boundaries and compensate DG connectees for previous payments may raise a challenge from the demand side where there have also been changes to connection charging policy – for instance, the introduction of the 25% rule in 1995 and the change to "shallowish" charging in 2005. Of course, a similar exercise to that described above for all demand connections since 1995 would represent a quantum leap in the volumes of work assessed above.
- Even if restricted to generation connections, such an exercise would set an expectation that similar exercises would be undertaken in future in the event of any further change to the connection or use of system charging policy.
- It is not clear that there is any right for DNOs under the connection agreements already sent to you to impose ongoing GDUoS charges. Such charges were certainly not envisaged when the contractual right to connect to and use the system was explicitly granted to users. Even with the compensation arrangements envisaged under this option, we would expect a significant number of disputes and determinations being required to impose this requirement on existing DG.
- Finally, there is the question of auditability of the compensation sums involved. Audit has been required in the recent BETTA transition arrangements for the 6 sites, where there has at least been a reasonable amount of accurate records to base the analysis and compensation amounts upon. With the greater amount of estimating that would be required for a similar exercise at distribution level, this raises the issue of the auditability of the results and the potential risk to DNOs if payments are made but later, there is any audit or Ofgem query on the basis of such payments.

In relation to Ofgem's specific questions on option c2) in the consultation paper, we reproduce these, followed by our response, below.

Is it workable?

No. All our discussion above, based on experience from the BETTA process, leads to the conclusion that a similar exercise for the 3-4000 DG connections, for which there is much less supporting information, would be totally unworkable. We believe that a disproportionate amount of time and effort would be involved in establishing or estimating the required details and that this would not be a satisfactory basis, overall, on which to establish compensation payments to third parties.

Does it meet the relevant licence objectives as well as the objectives described above?

We make the following observations on the relevant objectives for use of system charging methodology set out in the licence, when considered in relation to this option.

- One of the obligations on a distribution business set out in the Act is to develop and maintain an efficient, co-ordinated and economical system of electricity distribution. It is not efficient, in our view, for the distribution business to undertake exercises to reassess connection charges that parties would have paid in the past if connection policy had been different at that time.
- We do not believe that competition in supply is facilitated by complex distribution charging methodologies. In similar vein, we believe that investment and competition in the generation market is undermined if regulatory risk is perceived to rise. In our view, this would be the case if there were to be any imposition of a new liability for ongoing charges for existing DG where none existed before.
- In considering cost reflectivity of charges which, as we have noted before, is not an absolute concept, it is important to be mindful of the provision to take into account reasonable practicability and implementation costs. On these bases, the exercise contemplated in option c2) would not merit the significant effort involved even if it could be unequivocally demonstrated that the resulting charges were more cost reflective (which we doubt).
- The final relevant objective concerns developments in the licensee's distribution business. In our view, the most appropriate way for DNOs to take into account the increase in DG that is expected over the next few years is to set out appropriate ways of dealing with all DG going forward, that does not undermine the commercial position of existing DG. Offering incentives to move to new arrangements is a more efficient and sustainable approach than seeking to impose unfavourable terms onto existing connectees.

What information would be required in order to implement this option?

We have explored information requirements and associated difficulties above and in Appendix 2.

Is there an alternative to this option that fulfils the objectives?

In our view, option a) is the only feasible one. When allied with a method of demonstrating the economic need for distribution reinforcement, as discussed above and in Ofgem's paper, we believe that a better fit with the licence objectives and those relating to Ofgem's policy would be found.

Conclusion

We believe that the inevitable conclusion of our detailed review of the practical aspects of option c2) is that this option is unworkable given the significant and disproportionate effort that would be required to follow it through and the data difficulties that it entails. Options b) and c1) involve undermining the property rights of existing DG, which would be unacceptable to existing DG and therefore risk legal challenge.

This analysis suggests that option a) is the only feasible approach. Ofgem's remaining concerns about this approach could perhaps be alleviated by the development of other economic approaches to the assessment of DG-related investments requirements going forward, as discussed above and in Ofgem's paper. In any event, we are strongly of the view that any signals to DG have to be given on a forward-looking basis, rather than by attempting to "rewrite history" and unpick the intent of historic contractual arrangements entered into in good faith in earlier decades.

Regarding joint use assets, the same data difficulties and resource implications that affect option c2) are also entailed in any retrospective analysis of what "joint use assets" were involved in any deep connection. The picture then becomes further complicated when any of these assets, once identified, come to be refurbished as the natural development of the network system and growth of other demand/generation connections would necessarily affect the assessment of the proportion of joint use assets continuing to be used by the DG connections.

The only feasible approach, in our view, is to accept that over the decades, DG has paid whatever was required under the prevailing policy to "join" the system on the clear understanding that there would be no liability for use of system payments going forward. The only subsequent need for financing would be in relation to their sole user assets when these need to be replaced. On this basis, the ongoing funding of the interconnected system has been supported by demand charges. We do not consider that this raises any cross-subsidy issues as demand pays all the costs of the distribution networks either directly or via charges made by generators to suppliers in any case. Similarly, the current "shallowish connection charge plus GDUoS payments" could be viewed as a means to spread the required reinforcement costs on an average basis over the population of newly connecting DG, putting them in a similar position, over time, to the earlier DG that paid up front on a "deep basis". As we have found, some DG would certainly prefer to pay deep connection charges on a one-off basis as this reduces uncertainties in relation to project finance and could arguably, in fact, be less of a barrier to entry than having to assume an ongoing GDUoS liability.

Way Forward

Going forward, therefore, our clear preference for developing arrangements for DG, in the context of use of system charging methodology, is to draw a line at April 2005 and not require DG already existing at this point to pay GDUoS. This breakpoint is consistent with a wider scope of network developments including the introduction of GB wide trading and transmission arrangements. Ofgem's previous statements on policy for pre-existing DG, for example in the November 2003 initial decision document, were that the position of such DG would be reviewed in 2006 and there is therefore no regulatory commitment to require such charges to be imposed.

Any policy developments for the enduring framework going forward, for example the potential approach to constraint payments, should then apply equally to all connected DG.

Development of Distribution Use of System Charges In the North of Scotland

Background

There are two elements of the historic and political background in the north of Scotland that, in our view, represent constraints on the way that distribution use of system charging methodology can be developed in SHEPD's distribution services area. Firstly, the integral development of the hydro generation assets with the network infrastructure in the north of Scotland, and secondly the legacy of the common tariff obligation. These are discussed in turn below.

Hydro Generation Assets

The initial development of the whole electrical system in the north of Scotland in the early part of the twentieth century was founded on two political and economic motivations. These were: the harnessing of the potential for hydro-electric power in the mountainous regions of the north and west; and the development of a system of electricity distribution that would reach the remote areas of the country. The planning and development of the distribution system integrated these two themes, as a matter of government policy and thus, with public sector funding, the required electrical infrastructure was built.

With respect to the building of the hydro generation assets, the construction of dams and other civil works took place in parallel with the development of the electrical system. The dams and the reservoirs that they create are long-lived assets, capable of lasting for hundreds, if not thousands, of years. These assets were considered to have an indefinite life in accounting terms and were maintained, in practical terms, on the same basis. The maintenance of these assets is subject to the Reservoirs Act 1975, which involves periodic certification by third parties that maintenance has been carried out to the high standards required to ensure continued operation and availability for the foreseeable future. Thus, the legitimate expectation for owners of these assets is that they will continue to form the infrastructure for hydro-electric generation indefinitely.

In SHEPD's area, some 500MW of hydro-based DG was built in the post-war period. As discussed above, this was built in an integrated manner with the development of the electrical system and well before any concept of "deep" or "shallow" connection charging policy came into play. Arguably, there was actually no existing distribution system at all when the hydro generation was planned. The question of what connection charge was paid in these decades does not make sense and there are no records on which any assessment of this could reasonably be based. The same applies to any notion of "joint use" assets. However, the economic use of the hydro generation assets continues on an indefinite basis due to the long-lived nature of the civil infrastructure discussed above. The economics of such capital intensive generation facilities requires that they continue to represent an economic generation option for many decades.

Thus, in relation to Ofgem's consideration of the "c2" option discussed in the ISG paper, we would argue strongly against any proposal, were this option ultimately to be progressed, that a suitable point in time before which there would be no consideration of compensation would be 1990. The financing period for such long-lived and high capital cost assets is naturally much longer than that for wind farms, for example.

Common Tariff Obligation

Once the infrastructure had been built to bring “power to the glens”, it became a political objective to sustain the economic opportunity that this represented for the more remote areas of the north of Scotland by ensuring that prices charged for electricity did not vary geographically across the north of Scotland. As a corollary, it was accepted that costs would be geographically averaged across the area in order to arrive at a uniform approach to charging for electricity.

At the time of privatisation, this objective was translated into the “common tariff obligation” whereby, under an Order laid under section 3 of the Electricity Act 1989, the north of Scotland was specified as an area in which tariff prices would not be geographically differentiated. As the electricity market evolved towards the separation of businesses, this provision of the 1989 Act was amended by the Utilities Act 2000. Section 7B of the 1989 Act, as amended, allows the Secretary of State to require transmission, distribution and supply licensees to set charges which do not distinguish between users in different parts of a specified area in Scotland. An Order¹ under section 7 of the Act has been laid, which specifically requires distribution licensees whose authorised area includes the north of Scotland not to take into account geographical location in setting charges relating to domestic premises in that area.

The Order mentioned above explicitly prohibits geographic variation in charging for domestic customers. In considering the development of a coherent and consistent use of system charging methodology, the application of standard condition 4C (Non-Discrimination in the Provision of Use of System and Connection) is relevant. We are aware that Ofgem has made reference to the relevance of this licence condition in the context of the reference price control arrangements for independent DNO (IDNO) - or out-of-area DNO - networks. Again, the formal price control obligation (standard condition BA1) explicitly controls the level of IDNO charges for domestic customers. However, Ofgem’s view² was that the application of standard condition 4C also protects non-domestic customers.

Taking into account the statutory and regulatory background affecting the north of Scotland, therefore, it would not be SSE’s intention to introduce charges for users of the distribution system in SHEPD’s area that are differentiated on a geographic basis. With this constraint on the output of the charging models, it will naturally be more cost effective and efficient for the enduring model for distribution use of system charging in this area to be as simple as possible and take a cost attribution, rather than long run marginal cost-based approach.

¹ SI 2005/490

² Set out in the July 2005 decision document “Regulation of Independent Electricity Distribution Network Operators” (176/05).

Consideration of Resources Required to Implement Option c2

The following steps are considered necessary to undertake a review of the compensation sums required under option c2) in Ofgem's paper. Rough estimates of the amount of time needed for each stage have been made in order to obtain an order of magnitude of resources required. The estimates would require to be revisited if more precise figures were needed.

For each existing DG site:

1. Find details of the connection charges made and the engineering work done;
2. Potential site survey for those where details cannot be found (% of total sites);
3. Analysis of connection information found/surveyed to determine probable deep and "shallowish" connection boundary in order to assess the difference between these two boundary points in terms of assets employed covered by old and new connection policy – the "compensation asset";
4. Valuation of the compensation asset, including allowance for depreciation, price re-basing and any adjustments required for capitalised operation and maintenance payments made to determine the "compensation sum";
5. Amendment of the relevant connection agreement to require ongoing payment of GDUoS less the compensation sum, to involve discussion with the customer on the phasing of the compensation and other details of the calculation.
6. Preparation of material for auditors on the compensation sums paid.

Ofgem will be aware of the volume of existing DG sites and the difficulties that DNOs have had in providing basic details for all of these due to the lack of records extending over some decades. Once the connection work has been carried out, there is no operational reason for DNOs to retain the engineering details involved. The offer for connection lapses once the connection is established and it is the connection agreement, which does not contain details of what work was required, that determines the legal relationship going forward.

For SSE, there are approximately 200 DG connected under previous connection arrangements in SHEPD's area and 380 or so in the SEPD's area. We imagine that at least some other DNO areas are likely to have similar volumes of existing DG to consider, leading to a total number of existing DG connections of some 300 x 14 DNO areas, or 3-4000. Ofgem's paper refers to the ability of new DG to opt into the "shallowish connection plus GDUoS" arrangements prior to 1 April 2005 if they wished. It is worth noting that, in both SHEPD and SEPD areas, absolutely no DG wished to do this and in fact, there was a rush by generators to have their connection terms quoted on the old, deep charging basis, to minimise their uncertainties and project risk going forward. Thus, there are a significant number of sites, in addition to the above approximate numbers, with contractual offers of connection on the old basis, which have not yet been built, but which would also need to be adjusted in any mass compensation exercise.

Turning to the detailed steps noted above, it could in our view, take a significant time to search for records of engineering work carried out for a particular connection. There would be a need to check through various files and archives in different locations, reflecting the various office moves that have occurred over the decades. Ultimately, this effort could be fruitless but would still require to be undertaken as part of any mass programme to make the best estimate

possible of compensation assets. As a rough estimate going forward, we have allowed 0.5 of a day for this task.

Once any available historic information has been found, we estimate it would take between 0.25 and 0.6 (increasing for the older sites) of an engineer’s day to review the material, on a particular DG’s connection details. In old files typically containing costings for a number of connection options, it can be difficult to pin down exactly what work was carried out and the charges applied. We expect that follow up conversations and e-mails with colleagues who may have had an involvement with the connection (if still employed in the company) would be necessary to clarify what was actually done at the site. If there were insufficient engineering data, a site survey would be required to establish connection details. Some sites, particularly in SHEPD’s area would involve significant travelling times. For the purposes of this estimate, we have allowed a day for this activity for sites in SEPD’s area and two days for SHEPD’s area for a proportion of the existing DG sites.

Once the information gathering part of the exercise has been completed, we estimate that it would take perhaps 0.5 days of engineering time to carry out steps 3 and 4 above. This would have to involve some estimates of circuit loadings at time of initial DG connection in order to establish the equivalent “shallowish” boundary at historic connection time. This would obviously get more complex and less certain for earlier connection dates and the picture would be further complicated in the case of DG sites which had been upgraded to require further infrastructure development after the initial connection date.

If, say, 50% of the existing DG connections required a visit, the sort of time that might be required simply to provide an assessment of the relevant compensation sums on the above basis is as follows:

	<u>SHEPD</u>	<u>SEPD</u>
Approximate no. of sites	200	380
Sites needing a visit	100	190
Days per site to:		
- find material	0.5	0.5
- review material (average)	0.4	0.4
- carry out steps 3&4	0.5	0.5
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	1.4	1.4
extra days for visits	2	1
total days for visits	200	190
other days to prepare	280	532
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total days required	480	722

Thus, an initial estimate of 144 man weeks effort for the SEPD’s area and 96 for SHEPD’s area could be made of the sort of order of magnitude of engineering time that would be required to produce the basic estimates of the compensation sums. This might include the preparation of information for auditors, as noted under step 6, but it does not include the time necessary for discussions with the individual DG owners to obtain their agreement to the

compensation amounts and the introduction of a GDUoS payment obligation (point 5 above). It also does not include the time that would be required from support staff assisting in the engineering exercise or any billing-related costs in terms of IT developments and ongoing billing costs.