2005 GENERATOR TESTING CHARGES

Background and Calculation

A consultation paper by ESB National Grid

13th January 2005

Contents

1.0 Introduction

Generator Test Charges were first developed, consulted on and applied by the TSO in 2002 [1]. The same charges were applied in 2003 but were adjusted for inflation for application in 2004 [2]. This consultation paper considers the impact of changes to the Irish generation portfolio, generation costs and modifications to the operating reserve policy that have occurred since 2002 and proposes updated and more comprehensive generation test charges for application in 2005 through to 2007. Comments are invited on the Generator Test Charge calculation methodology set out in this document. The costs associated with the various components of the Testing Charge are presented for information.

Testing of a new generating unit, or an existing generating unit returning from major overhaul, is generally required in advance of the plant becoming fully operational. During a test the generator commonly requires that it be run at certain levels of output or a certain profiled output. It may not be possible to accurately predict the actual level of output of the unit at any specific time and there may be a significantly higher risk of a fault than for a fully commissioned generator. The unit is not available to the Transmission System Operator (TSO) for conventional dispatch (although the unit is issued with dispatch instructions) when it is under test.

These factors lead to increased system operating costs for the TSO for several reasons. The TSO will not be able to predict the output of the unit under test in advance with any degree of confidence, as it is common for tests to be cancelled at short notice or to vary significantly from their nominated level of output. To match supply and demand, the TSO will generally have to commit extra units to ensure a rapid response to changes from the unit under test's scheduled output and to ensure that the system would remain within normal security standards following the loss of the unit. As the unit under test is at a significantly higher risk of tripping, the TSO will carry additional operating reserve to ensure that security of supply is not compromised. This leads to additional constraint costs through the trading and settlement rules and increased reserve premium payments.

These costs are a component of the overall costs of installing a new generator or refurbishing an existing generator. It is therefore appropriate that these costs should be paid by the generator and recovered over the lifetime of the plant through the energy market. However, the actual costs caused by the unit under test are highly volatile and dependent on many factors outside the generator's control. There is little benefit to the market in exposing the generator to this risk, as the generator will not be in a position to manage the risk and reduce costs. Hence, based on the outcome of the 2002 consultation [1], generators pay for the costs of testing based on an ex ante published schedule of charges. The TSO will manage the volatility and magnitude of actual costs while ensuring system security on a daily basis.

An existing generator that elects to undergo a period of testing may request that the TSO deems them under test for a period of time. Should the TSO accede to this request the generator shall enjoy certain benefits of being treated in this manner for the period of the test. These include the flexibility to schedule output and conduct unit tests with the exemption from specific application of Short Notice Redeclaration charges and, potentially, exemption from specific application of Trip and Fast Wind-Down charges.

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The CER will review these proposals, their impact and industry submissions following this consultation process.

2.0 Scope & Application of Testing Charges

The generator testing charges set out in this document apply to all existing and future generating facilities that are intended to be dispatchable once fully commissioned and which are deemed to be under test as determined by the TSO.

It is proposed that the charges set out in this document would not apply to wind generation under test. Wind farms with outputs of more than 100MW would however incur 'Trip and Fast Wind-Down' charges in line with normal charging policy [2].

Testing Charges are defined on a €/MWh rate that varies according to the 'generated' (i.e at the output at the generator terminals rather than at the H.V. side of the generator transformer) output of the unit under test. Charges are applied based on the aggregated half-hourly, non loss factor adjusted, generated output of the unit.

It is intended that the charges determined in this document would be first applied in 2005 and subsequently recalculated for application in 2006 and 2007. The recalculation of the charges in 2006 and 2007 would be based on the impact of changes to the generation portfolio, operating reserve policy and operating costs but would not consider any change to the methodology behind the costs. It is proposed that testing charges for application in 2008 would be based on a detailed review of the actual testing charge calculation methodology. The charges quoted in this paper are based on 2005 rates and costs.

It should be noted that units under test are not eligible for payments for any Ancillary Services.

3.0 Test Phase Criteria

In order that costs to generators are minimised, three distinct phases of testing have been identified. Phase 1 will cover the initial period when the unit under test is considered highly unreliable and presents a large risk to the system. As the unit progresses through testing it enters Phase 2 then Phase 3 as it passes key testing milestones. As the unit is deemed to have completed each phase it is considered more reliable and hence different TSO operational policies will apply. During Phase 1 and Phase 2 of testing it will be necessary to carry additional spinning reserve. Phase 3 of testing represents normal operating reserve conditions. As each policy will result in different costs a different schedule of charges will apply to each phase of the testing programme.

Generators commissioning for the first time will be deemed to commence testing in Phase 1. Existing generators that require a period of testing after a major outage will generally expect to be in a position to operate sufficiently reliably to be deemed to be in Phase 2 testing. The TSO will determine into which phase a unit commences testing.

The Test Phase criteria set out for here are designed to be a simple test of a unit's reliability that drives defined reserve requirements and by implication the cost to the TSO. In reality, reserve requirements may vary from those defined in this policy as operating conditions have to be taken into account.

Account may be taken of any request issued by the TSO to the unit under test that causes it to deviate from achieving the minimum running levels specified by the Phase 1 or Phase 2 criteria. Note that a unit under test is not normally dispatchable by the TSO however, for system security reasons, the TSO may issue such an instruction. The TSO may consider setting alternative Phase 1 and Phase 2 test criteria in individual cases where the achievability of the criteria specified here are considered to be impractical.

3.1 Test Criteria Reference

The completion of the different phases of testing is based on a simple assessment of the reliability of the unit. The unit output is measured against the 'Normal Maximum Continuous Generation Capacity' of the unit and defined minimum running requirements that the generator must achieve before proceeding to the next reliability level are set. The 'Normal Maximum Continuous Generation Capacity' value is defined in the Generator's Connection Application form contained in the Generator's Connection Agreement. If this data is not available the TSO will determine the 'Normal Maximum Continuous Generation Capacity' of the unit in consultation with the generator.

When testing individual units in sequential stages on a multi shaft CCGT module (i.e. gas turbine and steam turbine units are on separate shafts) the module output is measured against the Normal Maximum Continuous Generation Capacity of the individual unit under test. When testing units together (i.e. a gas unit and a steam unit) the module output is measured against the 'Normal Maximum Continuous Generation Capacity' of the combined units. When testing as a combined module the phase of testing that the module is considered to be in will be the lowest test Phase of any of the units.

Take the example of a 310MW multi shaft CCGT module consisting of two 100MW gas unit and one 110MW steam unit. Each gas unit may test individually and proceed through Phase 1 and Phase 2 tests based on each unit's output measured against 100MW. When it comes to commissioning the steam unit, this will commence in Phase 1 for both gas and steam units, even if the gas units have already passed through Phase 1 testing, and will be measured against a combined capacity of 310MW.

3.2 Phase 1 Test Criteria

In this phase, the unit is considered to be highly unreliable and it is necessary to have sufficient reserve on line to cover 100% of the MW produced by the generator under test [3]. Reserve provided by interruptible loads will not be part of the primary reserve for this phase as these loads are only available for a limited number of interruptions per year and it would be imprudent to over utilise this resource during an unreliable operational phase [4]. To complete this phase the generator under test will have to complete a minimum:

- ***48 hours running at loads in the range 50%-100% of the 'Normal Maximum Continuous Generation Capacity' and***
- ***5 hours continuous running at loads in the range 75% - 100% of the 'Normal Maximum Continuous Generation Capacity'.***

The 5 hours of continuous running may contribute to the 48 hours of running in the range 50%-100%.

Any unreliable behaviour or known reliability problems occurring during any of these two sub-phases may require a repeat of that particular sub-phase.

Note that these criteria for passing Phase 1 of testing are less onerous than the existing criteria and should prove easier to achieve.

3.3 Phase 2 Test Criteria

The unit is assumed to be more reliable than in Phase1 but not as reliable as a unit in normal operation. Hence the overall reserve requirement is the same as in Phase 1, however, the unit is deemed to be sufficiently reliable to allow interruptible loads to contribute towards the reserve requirement. Sufficient reserve to cover 100% of the MW produced by the generator under test will be maintained.

To complete this phase the generator under test will have to complete a minimum of:

- ***72 hours continuous running at loads greater than 90% of the 'Normal Maximum Continuous Generation Capacity'.***

As with Phase 1, any tripping during the 72 hours will require a repeat of this phase. Any unreliable behaviour or known reliability problems occurring during this phase may require that Phase 1 operating conditions be restored.

Again, the criterion for passing Phase 2 of testing is less onerous than the existing criteria and should prove easier to achieve.

3.4 Phase 3 Test Criteria

At this stage of the commissioning programme the unit is deemed to be reasonably reliable and normal primary reserve rules will apply for the remainder of the reliability run.

Any tripping or unreliable behaviour or known reliability problems occurring during the reliability run may require a restart of Phase 2 with the appropriate operating conditions being restored.

The assessment of a unit's performance during Phase 1 and Phase 2 testing will be based on the aggregated half-hourly, non loss factor adjusted, generated output of the unit.

4.0 Cost Components & Calculation of Testing Charges

There are four distinct components to the TSO related costs associated with managing a unit under test that are included in this calculation of testing charges. The first three cost components discussed below (Constraint costs arising from Additional Reserve Requirements, Increased Cost of Reserve Premiums and Increased Run Hours) are associated with modifications to the TSO's operational policy when managing a unit under test. The fourth cost component, for Trips and Fast Wind Downs, is related to the performance of the unit which is something that is largely under the control of the generator. For this reason comment is invited on whether a fixed ex ante charge for Trip and Fast Wind Downs is included in the generator testing charges or whether this cost is recovered ex post on a 'per-trip' basis. Each of these components is discussed below with a corresponding description of how the cost was determined and analysis of the results.

There is an element of similarity between some of the cost drivers identified below. The methodology employed below recognises this and excludes any "double counting" of costs.

4.1 ADDITIONAL RESERVE REQUIREMENT CONSTRAINT COST

4.1.1 Cost Component

It is normally necessary to redispatch several units away from their nominated output to ensure the provision of sufficient operating reserve. This results in instructed imbalance payments being made to generators by the TSO. When the level of reserve required is increased (for example to facilitate unit test) the level of these costs increases.

4.1.2 Calculation Methodology

In order to capture this additional cost associated with a generation unit test, system production costs have been evaluated under a number of scenarios designed to reflect actual operational requirements and system conditions during 2005. Different test unit output levels and corresponding reserve requirements have been modelled. 2005 forecasts of fuel costs, plant mix, dispatch, interconnector flows and transmission network reinforcements have been made based on the TSO's 2005 Revenue Submission to the CER. The PROMOD IV® generation/transmission modelling package has been used in the calculation of these charges [5].

Studies were performed by comparing cases with 'normal' reserve requirements with cases with 'additional' reserve requirements driven by a unit under test. The unit under test was modelled as a new unit connected to the transmission network. These studies were repeated for a range of unit under test sizes from 50MW to 400MW. Each study evaluated the impact of a commissioning unit over a full year, hence a wide range of scenarios was modelled and highly representative results were obtained. The difference in production costs between corresponding 'normal' and 'additional' reserve requirement cases is the total additional cost that would be incurred by the TSO if the unit was under test for a full year and is therefore a good proxy of the corresponding constraint costs. Hence, the cost found is an accurate representation of the costs incurred under many different system conditions.

The difference in production costs for the normal and additional reserve requirement cases is then divided by the number of hours in a year to yield the average hourly cost of the reserve constraints over the period. This figure is then divided by the output of the unit under test to yield the cost per MWhr.

4.1.3 Results

Results are shown in the table below. Note that for a unit under test at loads below 250MW in Phase 1 and 300MW in Phase 2 there is no additional reserve requirement to that carried by ESBNG and the Northern Ireland TSO (SONI) under normal operational conditions. Hence there is therefore no additional reserve constraint cost under these conditions.

Generator Output	Phase 1 €/MWh	Phase 2 €/MWh
GEN <50	0.00	0.00
50 < GEN ≤ 100	0.00	0.00
100 < GEN ≤ 150	0.00	0.00
150 < GEN ≤ 200	0.00	0.00
200 < GEN ≤ 250	0.00	0.00
250 < GEN ≤ 300	1.88	0.00
300 < GEN ≤ 350	3.98	1.91
350 < GEN	7.30	4.13

Table 1 Cost Component Associated with Increased Reserve Requirement Constraint

For these studies, only the Primary Operating Reserve constraint was modelled [3]. This would, if anything, underestimate the additional costs. However, experience on the Irish system indicates that this approach, in general, yields accurate results for the constraint costs of reserve.

4.2 INCREASED COST OF RESERVE PREMIUMS

4.2.1 Cost Component

The TSO pays providers of reserve a Reserve Premium for the actual reserve level provided. This is separate from payments for out of merit generation under the Trading and Settlement Code as described above. When the TSO is carrying additional reserve, to facilitate a unit under test, additional Reserve Premium payments will be made.

4.2.2 Calculation Methodology

The reserve payment rates made to generators for providing operating reserve are published in the TSO's "Statement of Charges and Payments for Ancillary Services Providers" [6].

It is possible to accurately determine the additional reserve cost for every hour of commissioning in every phase based on the operational policy set out in Section 3. The cost of carrying additional Primary, Secondary, Tertiary 1 and Tertiary 2 reserve is included in this calculation [3].

4.2.3 Results

Results are shown in the table below. Note that for a unit under test at loads below 250MW in Phase 1 and Phase 2 there is no additional reserve requirement to that carried by the TSO under normal operational conditions. Hence there is therefore no additional reserve premium cost under these conditions.

Generator Output	Phase 1 €/MWh	Phase 2 €/MWh
GEN <50	0.00	0.00
50 < GEN ≤ 100	0.00	0.00
100 < GEN ≤ 150	0.00	0.00
150 < GEN ≤ 200	0.00	0.00
200 < GEN ≤ 250	0.00	0.00
250 < GEN ≤ 300	0.35	0.14
300 < GEN ≤ 350	1.18	0.98
350 < GEN	1.83	1.66

Table 2 Cost Component Associated with Increased Reserve Premium

4.3 ADDITIONAL RUN HOURS

4.3.1 Cost Component

As described above, units may be highly unreliable during testing. It is common for scheduled tests to be postponed, cancelled or completed early at short notice. If no mitigating action were taken, these situations could leave the system with insufficient committed plant. To reduce the risk to the system in these events, the TSO will commit the same plant, as it would otherwise have done if the unit under test were not present on the system. This will, however, appear as an instructed imbalance in the Settlement System and the TSO will incur additional constraint costs under the Trading and Settlement Code.

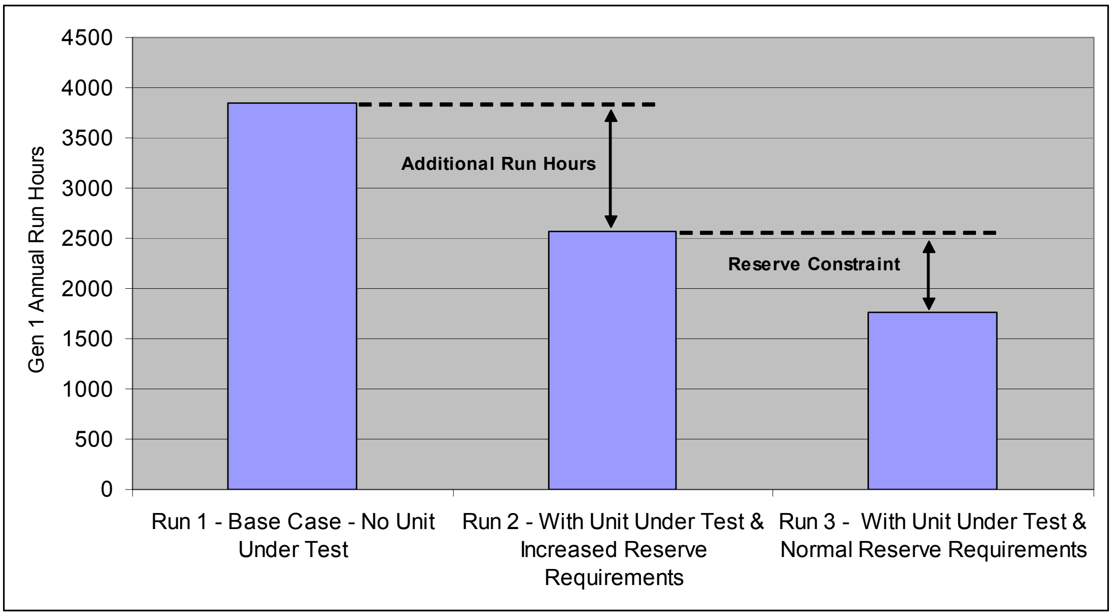
4.3.2 Calculation Methodology

The calculation of this charge is based on the total cost of additional 'run hours' (i.e. the number of hours that a unit was generating) for all units over a year (the year modelled was 2005) for a range of scenarios. For illustrative purposes, the 'run hours' of one particular existing marginal unit, called 'Gen 1', is highlighted in the methodology set out below and summarised by Graph 1.

Run 1: Represents a base case study which determined the number of 'run hours' over the year that each existing unit on the system would be expected to clock up. This case has no unit under test added. For illustrative purposes, these run hours are represented in Graph 1 below by unit 'Gen 1' in Run 1.

Run 2: A second study was run with a new unit added to reflect the addition of a unit under test and the resultant increased operating reserve requirement. This new unit was modelled as a high availability Best New Entrant and so displaced some existing lower merit generation as represented by the lower run hours of 'Gen 1' in Run 2 of Graph 1.

The difference in run hours between Run 1 and Run 2 represents the increased run hours that 'Gen 1' would have been committed by the TSO to cover the postponement, cancellation of early completion of a generator test run. The cost of these additional run hours are assumed to be represented by the number of hours multiplied by the units assumed idling or no-load cost (based on the average idle cost for each unit submitted in the first half of 2004 inflated to 2005 values). To prudently manage this cost it represents good operational practice not to retain all the marginal units that can start at short notice on-line at all times a unit is under test. It has been assumed for the purposes of this study that units that can start in under 30 minutes will not be kept on-line and so there is no additional run hour cost associated with these units. From the total cost of the additional run hours over a one year period the cost per MWhr of unit under test running has been determined.



Graph 1 – Annual 'Run Hours' for 'Gen 1' Under Different Scenarios

Run 3: A third study, based on Run 2 but with normal reserve requirements is presented for illustrative purposes. The difference in run hours between Run 2 and Run 3 reflect the impact of the increased reserve requirement in Run 2. The difference in production cost between these two cases forms the basis of the additional reserve requirement constraint charge derived in Section 4.1.

Again, the PROMOD IV® generation/transmission modelling package has been used in the derivation of this cost. With studies run over a full year designed to reflect actual operational requirements and system conditions during 2005. 2005 forecasts of fuel costs, plant mix, dispatch, interconnector flows and transmission network reinforcements have been made based on the TSO's 2005 Revenue Submission to the CER.

4.3.3 Results

Results are shown in the table below. It is noticeable that the rates are higher at lower unit under test output levels. There are a number of reasons for this: no additional operating reserve is required when test unit outputs are below 250MW hence all additional running hours are attributable to the additional run hour constraint; at unit under test outputs above 250MW substantial amounts of additional reserve is required and many additional run hours relate to the reserve constraint (which is reflected in the higher reserve constraint rates already included in Section 4.1); also at lower unit generation levels the cost of the additional run hours is spread over less MWhrs.

Generator Output	Phase 1 €/MWh	Phase 2 €/MWh
GEN <50	3.21	3.21
50 < GEN ≤ 100	2.98	2.98
100 < GEN ≤ 150	2.87	2.87
150 < GEN ≤ 200	2.81	2.81
200 < GEN ≤ 250	2.79	2.79
250 < GEN ≤ 300	1.79	2.72
300 < GEN ≤ 350	1.24	1.93
350 < GEN	0.05	1.17

Table 3 Cost Component Associated with Increased Run Hours

4.4 TRIP AND FAST WIND-DOWN CHARGES

The first three testing charge cost components identified above are designed to reflect the increased costs incurred as a result of altering the TSO's operating policy to manage a unit under test. The cost associated with unit trips and fast wind-downs is incurred on a 'per trip' basis rather than as a result of any change to TSO's operational policy while a unit is under test. Unit trips and fast wind-downs are largely under the control of the generator and as a result it may not be appropriate to charge for trips and fast wind-downs on an ex ante basis. Comment is requested on whether trip and fast wind-down charges should be included in these ex ante generator testing charges or whether trip and fast wind-down charges should be applied as normal on an ex post 'per-trip' basis. Actual trip and fast wind-down charges are published in the TSO's Statement of Charges [2]. The following sets out how the ex ante trip and fast wind down cost component was calculated.

4.4.1 Cost Component

Under normal operating conditions units may be liable for a charge if they trip or experience a fast wind-down while generating more than 100MW. Units under test are currently not liable for the application of trip and fast wind-down charges but would generally experience a significantly higher than normal number of both planned and unplanned trips and fast wind-downs. While the cost components calculated in sections 4.1 to 4.3 are based on the implications of carrying higher than normal reserve levels, this cost component is associated with recovering part of the cost associated with providing the basic level of operating reserve.

4.4.2 Calculation Methodology

Analysis of data from actual unit tests performed since 2002 has provided a useful benchmark for assumptions used in the calculation of this cost component. This data included the number of trips and fast wind downs actually experienced during test periods.
From this data a typical unit test profile was developed as shown in the table below. Based on these assumptions regarding test duration, unit load factor and number of trips during the test period a trip charge rate in €/MW can be calculated by dividing the trip charge by the corresponding energy production of the unit over a range of unit outputs.

	Test Duration (Days)		**Load Factor**		**Number of Trips /Fast Wind-Downs**	
	Phase 1	**Phase 2**	**Phase 1**	**Phase 2**	**Phase 1**	**Phase 2**
Gen Test	60	40	10%	50%	6	2

Table 4 Assumptions Made for Calculation of Trip Charge

The test profile assumptions listed above lead to a relatively benign estimate of the actual trip charge rate that would apply. The number of trips versus fast wind-downs is assumed to be split 50/50.

4.4.3 Results

Results are shown in the table below. As expected, trip charges increase as unit output increases and charges are greater in Phase 1 than Phase 2 as more trips are expected in Phase 1 than Phase 2 as the unit is considered to be less reliable. In line with existing policy, trip charges are not applied for trips of less than 100MW.

Generator Output	**Phase 1 €/MWh**	**Phase 2 €/MWh**
GEN <50	0.00	0.00
50 < GEN ≤ 100	0.00	0.00
100 < GEN ≤ 150	0.64	0.06
150 < GEN ≤ 200	1.92	0.19
200 < GEN ≤ 250	3.46	0.35
250 < GEN ≤ 300	5.13	0.51
300 < GEN ≤ 350	6.87	0.69
350 < GEN	8.65	0.87

Table 5 Cost Component Associated with Trips and Fast Wind-Downs

5.0 Other Costs

5.1 Constraint Costs

In order to facilitate a unit under test it may be necessary for the TSO to constrain the output of other generating units for thermal, voltage, stability or short circuit level reasons. This results in instructed imbalance payments being made to constrained generators by the TSO. This type of constraint is likely to occur if transmission reinforcements, associated with the connection of a new generating unit, are not completed at the time of unit testing.

While this constraint is distinct from the additional reserve constraint set out in section 4.1 there are likely to be interactions between these constraints.

The cost associated with any such constraint is difficult to quantify as it would depend on the location of the generator under test, the availability of other generating units, outages on the transmission system and the progress of new transmission reinforcements. As a result it is proposed that this cost component is not included in these Generator Testing Charges.

In line with the existing arrangements it is proposed that such constraint costs arising during a generator test would be recovered by the TSO through the TUoS tariff subject to CER approval.

5.2 Short Notice Redeclarations

Under normal operating conditions, Short Notice Redeclaration payments are made by generators who redeclare their availability at short notice (less than 4 hours). Such redeclarations can result in a constraint cost to the TSO as other generation must be redispatched, the payment from generators who make such Short Notice Redeclarations compensates for this constraint cost.

It is considered that the cost associated with Short Notice Redeclarations is covered by the Additional Run Hours and the Additional Reserve Constraint cost components of these Testing Charges. For this reason it is proposed that a unit under test will not be liable for the specific application of Short Notice Redeclaration charges.

5.3 TUoS Charges

Generators should be aware that they are also liable for a Non-Firm and/or Firm TUoS tariff from their synchronisation date. These tariffs are set out in the TSO's 'Statement of Charges' [2]. These TUoS tariffs are not included in the Generator Testing Charges set out in this document.

6.0 Schedule of Charges

The following table summarises the individual costs components derived in this document and total testing charges are indicated with and without the 'trip and fast wind-down' cost component.

Charges will be applied based on the aggregated Trading Period generated energy for each unit. Charges are specified for different unit outputs and testing phases.

Unit Output MWs	Reserve Constraint €/MWh	Additional Run Hours €/MWh	Reserve Premium €/MWh	Trips & Fast Wind-Downs €/MWh	**Total Test Charge with Trips included €/MWh**	**Total Test Charge with Trips excluded €/MWh**
PHASE 1						
GEN ≤ 50	0.00	3.21	0.00	0.00	**3.21**	**3.21**
50 <GEN≤ 100	0.00	2.98	0.00	0.00	**2.98**	**2.98**
100 <GEN≤ 150	0.00	2.87	0.00	0.64	**3.51**	**2.87**
150 <GEN≤ 200	0.00	2.81	0.00	1.92	**4.73**	**2.81**
200 <GEN≤ 250	0.00	2.79	0.00	3.46	**6.25**	**2.79**
250<GEN≤ 300	1.88	1.79	0.35	5.13	**9.14**	**4.01**
300 <GEN≤ 350	3.98	1.24	1.18	6.87	**13.26**	**6.39**
350 <GEN	7.30	0.05	1.83	8.65	**17.84**	**9.18**
PHASE 2						
GEN ≤ 50	0.00	3.21	0.00	0.00	**3.21**	**3.21**
50 <GEN≤ 100	0.00	2.98	0.00	0.00	**2.98**	**2.98**
100 <GEN≤ 150	0.00	2.87	0.00	0.06	**2.94**	**2.87**
150 <GEN≤ 200	0.00	2.81	0.00	0.19	**3.00**	**2.81**
200 <GEN≤ 250	0.00	2.79	0.00	0.35	**3.13**	**2.79**
250 <GEN≤ 300	0.00	2.72	0.14	0.51	**3.37**	**2.86**
300 <GEN≤ 350	1.91	1.93	0.98	0.69	**5.50**	**4.81**
350 <GEN	4.13	1.17	1.66	0.87	**7.82**	**6.96**

Table 6 Schedule of Generator Test Charges

The costs displayed in the table above are based on 2005 rates and prices.

No testing charge will be applied in respect of a generator in phase 3 of its commissioning programme.

7.0 Conclusions

This paper has developed a schedule of ex ante charges for generator testing. These charges are designed to recover the increased system operating costs associated with the TSO managing such tests and to limit the generators exposure to these highly volatile costs.

Testing Charges are defined on a €/MWh rate that varies according to the 'generated' (i.e at the output at the generator terminals rather than at the H.V. side of the generator transformer) output of the unit under test. Charges are applied based on the aggregated half-hourly, non loss factor adjusted, generated output of the unit.

The charges developed in this paper are reflective of the current operational policy and costs associated with managing a unit under test.

References

[1] Generator Testing – Background and Calculation of Commissioning Charges - A paper by ESB National Grid can be found on the EirGrid website (www.eirgrid.ie) on the Transmission Use of System Charges page under the Use of System Documents heading.

[2] ESB National Grid's 'Statement of Charges', which can be found on the EirGrid website (www.eirgrid.ie), contain Generator Commissioning Charges, Generator Direct Trip and Fast Wind Down Charges and Firm/Non Firm TUoS Charges.

[3] Details on Operating Reserve can be found in the December 2003, Ancillary Services, 'Operating Reserve' workshop presentation which can be found on the EirGrid website (www.eirgrid.ie).

[4] Details on ESB National Grid's Interruptible Load Scheme can be found in the 'July 2003 Workshop Presentation' which can be found on the EirGrid Website (www.eirgrid.ie).

[5] PROMOD IV® is an integrated energy market simulation and transmission analysis product produced by NewEnergy Associates, A Siemens Company.

[6] The rates for the different categories of Operating Reserve are contained in ESB National Grid's 'Statement of Charges and Payments for Ancillary Service Providers 2005' which can be found on the EirGrid website (www.eirgrid.ie).