Optimizing Generation Portfolio for Emission Control in Europe’s Utilities

Sanjay Neogi 1,1, Anindya Pradhan 2,1, Arup Sinha 2,2, S. Chowdhury 3,1, S.P. Chowdhury 3,2, C.T. Gaunt 3,3

1 Capgemini India Private Ltd.
E-mail: sanjayneogi@rediffmail.com

2 Tata Consultancy Services Ltd. Kolkata, India,
E-mail: anindya.pradhan@tcs.com arup.sinha@tcs.com

3 University of Cape Town Electrical Engineering Department Cape Town, South Africa,
E-mail: sunetra.chowdhury@uct.ac.za sp.chowdhury@uct.ac.za ct.gaunt@uct.ac.za

Abstract—European utilities in the recent times is going through a phase marked by notable changes. The market is opening up for competition; utilities are unbundling leading to the separation of wholesale retail and distribution sectors. Environmental and climate change requirements have gained significant importance and has considerable impact on the way utilities will be run and operated. The Kyoto Protocol mandates reduction of greenhouse gases by at least 5 percentages from the level of 1990 by (2008-2012) and the 20-20-20 plan aims to reduce 20% of greenhouse gases by 2020, compared with 1990 levels. The paper discusses the key issues and adopts a holistic view for a Generation Utility. The environmental impact on the Portfolio and merit order ranking is taken into account it goes into the various portfolio optimization options that a generation utility has to address to meet the environmental Challenges under various regulatory regimes such as EU ETS and Kyoto Protocol. In the next stage, it highlights couple of salient features such as Financial Transmission Right (FTR), Holding Period Returns (HPR) and Efficient Frontier and their effective use in negotiating emission challenge. The paper suggests a methodology to the generators for optimizing its operations and in conclusion, will highlight key options that may be adopted by the European utilities and the suggested way forwards.

Keywords—Generation Optimization, Emissions control, European Union—Emission Trading Scheme (EU-ETS), Financial Transmissions Rights (FTR),

I. NOMENCLATURE

- CCGT : Combined-Cycle Gas Turbine
- CHP : Combined Heat & Power
- EU : European Union
- ETS : Emission Trading Scheme
- FTR : Financial Transmission Right
- HPR : Holding Period Returns
- LMP : Local Margin Price
- LRMC : Long–run Marginal Cost
- MWh : Mega Watt Hour
- NER : New Entrants Reserve
- SRMC : Short-run Marginal Cost

II. INTRODUCTION

Electricity Generation Portfolio across European countries varies widely in terms of share of fossil fuels in power generation and carbon intensity from the plants. In countries like Poland, Netherlands, more than 90% of the generation mix comes from fossil fuels while in UK and Italy, nearly 75% of the generation mix comes from the same. On the contrary, Germany, Spain and Czech Republics generate approximately 60% from fossil fuels while France and Sweden have nearly 20% share of fossil fuels in their generation mix. [1][8]

In the same way, carbon intensity for coal plants across the European countries varies considerably. The Danish, Finnish and Swedish plants emit much less CO2 per kWh than their French or Italian counterparts. This is primarily due the higher average plant efficiency in Denmark and Finland as compared to France and Italy. For example in France, nuclear plants are run as base load plants at maximum efficiency while the coal plants are run as marginal units. The French coal plants have relatively low efficiency which results in a higher carbon emission as compared to the Danish base coal facilities. The lifetime of the plant also plays a vital role in deciding the carbon intensity. Swedish and Danish coal plants are comparatively younger in comparison to the Italian coal plants and thus have lower emissions. [3]

In this context, introduction of the Green Package, in January 2008, by European Commission, starting of the second phase of EU Emission Trading scheme (ETS) from 2008 and compliance with the Kyoto Protocol have shifted the focus on generation portfolio optimization for addressing emission control in European utilities. This paper discusses a methodology for the electricity generators for optimizing their operations in the wake of Emission Trading Scheme (ETS) in Europe.
A generator can optimize its generation portfolio in many ways to address emission control. Common methods are switching across plants or technologies, focusing on renewable, new versus old generation, efficiency improvements of the existing plants, closure of old plants etc.

Short-run Marginal Cost (SRMC) is the change in total cost resulting from a one-unit increase (or decrease) in the output of an existing production facility.

The electricity generators receiving free allowances under the EU ETS system can either use these allowances to cover the emissions resulting from the production or sell them to other companies that need additional allowances. Hence, for a generating company using an emission allowance, this represents an opportunity cost, regardless of whether the allowances are allocated for free or purchased at an auction. Therefore, a generating company is expected to add the costs of emission allowances to its SRMC or trading decisions, even if the allowances are granted for free. In many European countries, a strong correlation is observed between the CO2 price and electricity price. [18]

A merit order is created by arranging all the available generation capacity in the increasing order of their short run marginal costs and this order is used for the dispatch of electricity i.e. the plant with the minimum SRMC will be dispatched first followed by the others in the increasing order of the SRMC. This SRMC earlier depended mainly on the fuel costs, however with the emergence of emissions trading an additional cost has been added for emission allowances, the addition of these emission allowances to the SRMC will change the ranking of the Merit Order across the existing plants. In terms of SRMC, conventional hydro, wind and nuclear plants are highly preferred for supplying base load and have no impact on the merit order due to the addition of emission allowances as these emit no CO2 Thus if a Merit Order is created for various generation technologies without considering CO2 costs, hydro, nuclear and wind would be the cheapest to run, followed by coal, CCGT and gas. Whether a shift in generation mix will be encouraged by CO2 compliance requirement will however depend on whether the extra CO2 cost will prompt a change in the merit order causing some generation technologies to become more competitive than the others. [3]

Main characteristics of energy sources that are affected by CO2 emissions are listed in Table I below. It is evident from Table I that though the fuel cost for gas is higher than that for coal, but gas has much lower CO2 intensity than coal. Hence carbon cost affects coal much more than gas.

<table>
<thead>
<tr>
<th>Energy Source</th>
<th>CO₂ Intensity</th>
<th>Fuel Cost per unit Energy Output</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas</td>
<td>Low</td>
<td>Very High</td>
</tr>
<tr>
<td>Coal</td>
<td>High</td>
<td>Low</td>
</tr>
<tr>
<td>Uranium</td>
<td>None</td>
<td>Very Low</td>
</tr>
<tr>
<td>Wind</td>
<td>None</td>
<td>None</td>
</tr>
</tbody>
</table>

The thermal efficiencies and the emission factors that were considered for calculations of the marginal costs are shown in Table II below.

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Emission factor gCO₂/MJ</th>
<th>Thermal Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>94.6</td>
<td>43%</td>
</tr>
<tr>
<td>Oil</td>
<td>77.4</td>
<td>40%</td>
</tr>
<tr>
<td>Gas</td>
<td>55.8</td>
<td>55%</td>
</tr>
<tr>
<td>CHP coal</td>
<td>92.7</td>
<td>87%</td>
</tr>
<tr>
<td>CHP gas</td>
<td>55.8</td>
<td>88%</td>
</tr>
</tbody>
</table>

From Fig.1, it is observed that even though the Marginal cost of CHP Gas power plant is much higher than that for coal based power plant, but with the addition of carbon cost (assumed to be € 20/t here), the cost differential is decreasing and with higher CO₂ costs, the competitiveness may even be reversed.

For example there may be a change in Merit Order between the CCGT plants and coal plants due to the addition of the emission allowances. In general CCGT produces about 0.48 tCO₂/MWh of electricity, while a typical coal plant emits about 0.85 tCO₂/MWh. Assuming an average CO₂ price of €23/tCO₂, generation cost of CCGT increases by € 11.04/tCO₂/MWh while the same for the coal plant increases by € 19.55/tCO₂/MWh. [3] Thus, in many European countries, large scale CCGT plants, with much lower carbon intensity, are being commissioned.

Table III lists the CCGT plants that are planned to come up in the UK between 2009 and 2012.

Fig.1 shows the marginal cost of various generation technologies in Nord Pool market and impact of a € 20/tCO₂ carbon price.

Fig. 1 Marginal costs of various generation technologies, in Nord Pool market and Impact of a € 20/tCO₂ carbon price. [13]
### TABLE III
PLANNED GAS FIRED CAPACITY ADDITION IN UK [2]

<table>
<thead>
<tr>
<th>Plant</th>
<th>Owner</th>
<th>Capacity (MW)</th>
<th>Expected Onstream</th>
</tr>
</thead>
<tbody>
<tr>
<td>Marchwood</td>
<td>SSE/ESBI</td>
<td>340</td>
<td>2009</td>
</tr>
<tr>
<td>Langage 1</td>
<td>Centrica</td>
<td>350</td>
<td>2009</td>
</tr>
<tr>
<td>Barking Extension</td>
<td>Barking</td>
<td>470</td>
<td>2009</td>
</tr>
<tr>
<td>Grain CHP</td>
<td>E.on</td>
<td>360</td>
<td>2010</td>
</tr>
<tr>
<td>Staythorpe</td>
<td>RWE</td>
<td>425</td>
<td>2010</td>
</tr>
<tr>
<td>Inmingham 2 (CHP)</td>
<td>ConocoPhilips</td>
<td>450</td>
<td>2010</td>
</tr>
<tr>
<td>Uksmouth 2</td>
<td>Severn Power</td>
<td>340</td>
<td>2010</td>
</tr>
<tr>
<td>Pemborke 1</td>
<td>RWE</td>
<td>2000</td>
<td>2011</td>
</tr>
<tr>
<td>Drakelow</td>
<td>E.on</td>
<td>1200</td>
<td>2011</td>
</tr>
<tr>
<td>Grain 2 (CHP)</td>
<td>E.on</td>
<td>430</td>
<td>2011</td>
</tr>
<tr>
<td>Staythorpe 2</td>
<td>RWE</td>
<td>425</td>
<td>2011</td>
</tr>
<tr>
<td>Langage 2</td>
<td>Centrica</td>
<td>400</td>
<td>2011</td>
</tr>
<tr>
<td>West Burton 1</td>
<td>EdF</td>
<td>435</td>
<td>2011</td>
</tr>
<tr>
<td>Staythorpe 3</td>
<td>RWE</td>
<td>350</td>
<td>2012</td>
</tr>
<tr>
<td><strong>Total 2009-2012</strong></td>
<td></td>
<td><strong>10475</strong></td>
<td></td>
</tr>
</tbody>
</table>

Long-run Marginal Cost (LRMC) represents the full cost of the last power plant to enter the market. LRMC plays a significant role in deciding the long-term investment decision. LRMC include both the operating and capital cost required for the new capacity. For example, nuclear technology has a very high capital cost but a low operating cost and CCGT has a low per unit investment cost. [3] Apart from the factors discussed in previous sections, other external factors, such as fuel availability, network congestion, market structure, regulatory policy etc. play a major role in generation planning. For example, the Gas producers and suppliers in Europe have more market power than the suppliers of the other fuels. Market power of gas suppliers depends on the elasticity of demand for gas. [19].

### III. PROBLEM FORMULATION

#### A. EU-ETS – Business Driver and Constraints for Generation Optimization

European Union’s Emissions Trading Scheme (ETS) proposal covers two trading periods, 2005-2007 and 2008-2012. The second phase is the first commitment period of the Kyoto Protocol. Under this scheme, each facility (which are power stations greater than 20MW capacity, refineries, paper, pulp, minerals, metal plants) received tradable emission allowances by the national governance, where one allowance equals one metric tons of CO₂ emission. [3]

The second phase of the ETS (2008-2012) is more stringent as compared to the first one in terms financial penalty and allowable auction. The financial penalty charged per additional tonne of CO₂ is €100 for 2008-2012 period while it is only €40 in 2005-2007 period. Auctioning is increased to 10% in the second phase as compared to 5% in the first phase of ETS. The Green Package of European Commission proposes to increase the auctioning of allowances in the EU ETS after 2012 to achieve full auctioning by 2020. [3][15]

Allowances in Emission Trading can be distributed in four ways as listed below:

1. **Auctioning** – Here the participants in Emission Trading have to purchase the allowances from the market.
2. **Grandfathering** – Here the distribution of the allowances is free of charge and based on either the past emission levels or the external benchmarks.
3. **Updating** – Here the allowances are also distributed free of charge but the allocation for the second period depends on the allocations for the first period.
4. **Fixed Carbon Emission per output** – Here the total emission is not capped and companies can produce a variable amount of emission.

Auctioning eliminates the windfall profits due to free allocation of emission allowances but does not reduce the windfall profits due to ETS–induced changes in power prices.

The distinguishing features of the ETS are as follows:

1. **Updating Free Allowances to Incumbents** – In contrast to the “one–off” allocation of most US programmes (where allowances are allocated at the beginning of the programme), EU ETS scheme adopts a sequential approach. Here emission allocation plans are decided for one commitment period at a time with repeated negotiations for the allocations in the next period.
2. **Contingent Allocation to Plant Closure** – In free allocation of the allowances to the next period requires that the facility should remain open or active for minimum time duration during the present period. The key driver of this clause is to prevent closure of a plant because their operations become unprofitable due to emissions trading; whereas continuing the benefits from selling large amount of allowances allocated for free.
3. **Free Allocation to the New Entrants** - The first and second set of National Allocation Plans (NAPs I and II) of all Member States in the EU ETS include provisions for a New Entrants Reserve (NER) in order to allocate allowances for free to new installations. The key driver of this clause is to create fairness amongst the existing and new facilities. As the existing facilities receive allocation for free, so should the new entrants. [1][10]

Table IV shows an example of Emission Trading impact on the Generation Portfolio Optimization for EU.

### TABLE IV
IMPACT OF EMISSION TRADING ON GENERATION PORTFOLIO [1][10]

<table>
<thead>
<tr>
<th>Generation Portfolio Optimization</th>
<th>EU Emission Trading Key Clause</th>
</tr>
</thead>
<tbody>
<tr>
<td>Contingent Allocation to Plant Closure</td>
<td>Free Allocation to the New Entrants</td>
</tr>
</tbody>
</table>
B. Constraints in Generation optimization

For constraints in generation optimization, two different sets of factors are considered. The first set consists of external factors which are not controllable by the generation unit. The second set consists of internal factors.

1) External Factors

a) Network Congestion

The physical constraint on the capacity of a transmission route results in inconsistent locational prices at nodes (nodes represent places on the system where generators inject power into the system or where demand, or load, withdraws from the system. Each pricing node is related to one or more electrical buses on the power grid.) within a sub region.

The electricity price in the day-ahead market is determined by matching offers from generators to bids from consumers at each node to develop a classic supply-demand equilibrium price, usually on an hourly interval. This is calculated separately for sub regions for which the system operator's load flow model indicates that constraints will bind transmission imports.

In some US markets, the locational price at each node, called the Locational Marginal Price (LMP), is calculated. This calculation incorporates a security-constrained, least-cost dispatch calculation with supply based on the generators that submitted offers in the day-ahead market, and demand based on bids from load-serving entities draining supplies at the nodes under consideration.

The issue of differing locational prices at different nodes within a sub region puts the generator in a dilemma regarding which node to offer from. This issue is presently dealt with tradable financial derivative instruments (contracts) that ensure that the generator gets compensated for any kind of discrepancy in locational prices at different nodes. Such an instrument is not a tool for profit maximization or direct cost minimization but is for risk minimization. These contracts ensure that the generator gets paid if the locational price at the point of withdrawal (i.e. the node where the generator is selling electricity) is lower than that at the point of injection. But if the reverse happens then the generator is charged instead of getting reimbursed

b) Fuel Availability

Fuel availability is a macro-economic constraint that affects both SRMC and LRMC of generation. In case, materials are imported from a different geographical location, the import duties and the compounded natured tax structure increases the marginal costs especially the SRMC. On the other hand fuel availability is the limiting factor that decides the available capacity of the plant types.

It also affects the start-up costs of a plant as a fuel crisis can cause a plant to shut down. Start-up costs include incremental electricity usage costs in heating boilers, incremental production boost up costs etc.

c) Weather

Weather is a limiting factor more in case of renewables like wind energy rather than for other generation technologies. Weather affects both demand determining factors like nodal loads (e.g. season affecting nodal demands) and supply determining factors like wind speeds.

b) Other factors

Other factors, such as, market structure (competition), regulatory policy (distribution of emission allowances, windfall profit treatment), technology obsolescence etc. also play some role.[9]

2) Key Internal Plant Operational Factors

a) Operating Cost

Operating cost covers a major portion of overall cost of operation. It includes fuel cost and operation and maintenance costs.

b) Carbon Abatement Cost

Though it is a limiting factor from a cost minimization perspective, abatement cost is compensated through Emission Trading Schemes and allocation mechanisms like grandfathering. This gives existing generating installations an edge over new entrants as they are based on past emission levels.

c) Start up Cost & Ramp-up/down Rate

Once a shut down occurs, many costs of incremental nature creep in on restarting the plant. For example, incremental electricity usage on heating boilers, incremental gear up costs etc.

Moreover, apart from total production, total number of start and stops also affects the total emission cost. This is because CO2 emitted in the start up process adds to the cost. [5]

Similarly the Ramp-up & Ramp down rate play a major role in generation optimization.

C. Utility of a Point to Point Financial Transmission Right (FTR) from the Generator’s Viewpoint

In this paper, the authors consider two nodes, A – the point of injection and B – the point of withdrawal.

It is assumed that the day ahead hourly LMP at node A is 50 units of currency/MWh and for the node B is 20 units of currency/MWh. If the generator holds a point to point transmission right from A to B then the generator should get (50 – 20) i.e. 30 units of currency/MWh on the next day. But this does not occur in practice because of the following reason:

If suppose the next hourly day ahead LMP at node A changes to 30 units of currency/MWh and that for node B changes to 40 units of currency/MWh, then there is a negative pay off i.e. the generator now is supposed to pay (40 – 30) i.e. 10 units of currency/MWh on the next day.

So the previous pay off of 30 units of currency/MWh is now offset by the negative pay off of 10 units of
currency/MWh. The cumulative effect is that the generator is now supposed to get $(30 - 10)$ i.e. $20$ units of currency/MWh on the next day if Hour #2 is the last hour of the trading day.

Now, if the next day (i.e. Day 2) is the date of maturity (or the date of expiry) of the FTR, then the hourly day ahead LMP does not exist. In that case, the hourly spot LMP comes into the calculation. So the difference between the spot hourly LMPs between the two nodes are taken into consideration.

If it is assumed that the spot hourly LMPs for Day 2 are as shown Table V, the cumulative effect would be that the generator actually gets paid $(30-10)$ i.e. $20$ units of currency/MWh.

So if the generator continues to hold the FTR it actually gets paid $20$ units of currency/MWh eventually. But the risk in continuing to hold the FTR till the maturity date is that the generator might eventually have to pay instead of getting paid. Generally, generators do not hold the FTR till its maturity date. It may be mentioned here that there exists another type of FTR termed flow based FTR. In this paper, the authors have considered the most basic variant of an FTR – the point to point FTR. [15][16]

Net FTR pay off calculations from the generator’s viewpoint is shown in Table V.

### Table V

<table>
<thead>
<tr>
<th></th>
<th>Node A (Point of Injection)</th>
<th>Node B (Point of Withdrawal)</th>
<th>Pay off for the Generator</th>
</tr>
</thead>
<tbody>
<tr>
<td>Day 1</td>
<td>Day ahead LMP (units of currency/MWh)</td>
<td>50</td>
<td>20</td>
</tr>
<tr>
<td></td>
<td>Day ahead LMP (units of currency/MWh)</td>
<td>30</td>
<td>40</td>
</tr>
<tr>
<td>Day 2</td>
<td>Spot LMP (units of currency/MWh)</td>
<td>50</td>
<td>20</td>
</tr>
<tr>
<td></td>
<td>Spot LMP (units of currency/MWh)</td>
<td>30</td>
<td>40</td>
</tr>
</tbody>
</table>

**D. Model Schema for Generation Optimization**

The proposed schema for generation optimization focuses on cost minimization more from the operational perspective rather than from the strategic capital investment perspective. It also takes into account the carbon emissions by incorporating carbon abatement costs. Apart from just focusing on cost minimization from an operational perspective, the proposed schema also incorporates a congestion hedging mechanism to compensate the generator for the discrepancy in locational marginal prices at injection and withdrawal nodes in a sub region. This is done through tradable derivative instruments (contracts) called point to point financial transmission rights (FTR).

It must be borne in mind that point to point FTRs are not tools for direct cost minimization. Instead they facilitate risk minimization. As mentioned earlier, these contracts ensure that the generator gets paid if the locational price at the point of withdrawal (i.e. the node where the generator is selling electricity) is lesser than that at the point of injection. But if the reverse happens then the generator is charged instead of getting reimbursed. The quantum of compensation or charge whatever the case may be is the difference between the hourly day ahead locational prices at the injection and withdrawal nodes.

**E. Representation of the Model Schema**

The model schema is represented with a set of parameters as the input and subsequent iterative processes. Fig.2 shows the model schema in the flow chart form.

In this paper, the model shows how a generating company with multiple plants can optimize its cost of operations to meet its demand. The model uses the available plant types and available capacities as inputs. Available plant types include the plant technologies available to a generating company and available capacity means the amount of electricity in Megawatts that the plant can deliver during the time period for which planning is done. The available capacity takes into account factors like fuel availability and wind availability in case of wind generation.

In order to optimize the cost of operations, the load is first supplied from the most economical plant and the rest in the ascending order of marginal production cost. The marginal production cost comprises the operating cost which includes fuel cost, cost due to carbon compliance and start-up cost of the unit (if the unit is not in a running state). The model first determines the marginal production cost of each unit and then arranges them in an ascending order thereby forming a Merit Order of all the technologies. Then, with the demand forecast, it schedules the units according to the Merit Order. Thus by meeting the demand in the most economical way the generating company minimizes its cost of operation. Point to point FTR is a financial derivative contract that compensates the generator to the extent of the difference between the hourly day ahead LMPs at the injection and the withdrawal nodes. The generator continues to get compensated in real time each hour as long as the hourly day ahead LMP at the withdrawal node is lower than that at the injection node. The generator gets charged instead of getting compensated as soon as the reverse occurs.

If there is any network congestion, a constraint may be imposed on the generation units on the amount of electricity it can supply. In that case, irrespective of the generating capacity or the marginal cost of the plant, it can only supply electricity equal to the available transmission capacity and the remaining demand must be met by a unit with the next lowest cost of production which has available transmission capacity.

The generation planning is affected by other exogenous
factors such as fuel availability, the weather forecast as well as internal factors such as planned outages or maintenance schedules of the plants. These factors are not directly accounted for in this schema, but the input “available plant types” accounts for these factors as the plant availability depends on these factors such as fuel availability, weather conditions (for wind generators) and planned outages.

IV. LONG TERM GENERATION PORTFOLIO OPTIMIZATION

The long term generation portfolio of a utility can be optimized using the portfolio theory in finance. According to this theory, first the expected portfolio cost and the expected portfolio risk are calculated and are plotted on a graph for various available portfolio alternatives. Thus a frontier of the portfolios with the lowest expected cost for a particular level of risk undertaken is obtained. The generator can select any of the portfolios falling on the efficient frontier making a risk–cost trade-off based on their risk aversion.

A. Defining Expected Generation Portfolio Cost

Expected Portfolio Cost per kWh of generation

\[ X_1 E(C_1) + X_2 E(C_2) \]

where,

\( E(C_1), E(C_2) \): Expected annual generation costs per kWh for technologies ‘1’ and ‘2’ respectively

\( X_1, X_2 \): Proportion of aggregate annual generation contributed by technologies ‘1’ and ‘2’ respectively in the portfolio.

For \( n \) generation technologies the expression is:
B. Definition of “Risk” And “Holding Period Return” In the Generation Optimization Context

The expected portfolio risk can be defined as follows:

(a) Expected portfolio risk for a two asset portfolio, is given by

\[
E(\sigma_p) = \sqrt{X_1^2 \sigma_1^2 + X_2^2 \sigma_2^2 + 2X_1X_2 \rho_{12} \sigma_1 \sigma_2}
\]

Where,

- \( \sigma_1, \sigma_2 \) : standard deviation of holding period returns of annual costs of technologies ‘1’ and ‘2’ respectively.
- \( \rho_{12} \) : correlation between holding period returns of technology ‘1’ and technology ‘2’

(b) A more generalized notation for expected portfolio risk would be of the form:

\[
E(\sigma_p) = \sqrt{\sum_i X_i^2 \sigma_i^2 + 2 \sum_{i \neq j} X_iX_j \rho_{ij} \sigma_i \sigma_j}
\]

\( X_i \) : proportion of aggregate annual cost per kWh accounted for by the \( i \)th cost type within technology ‘1’. \([14]\)

C. Efficient Frontier

After defining expected portfolio cost and expected portfolio risk, it is possible to plot the efficient frontier. Efficient frontier is basically the locus of all the points corresponding to the minimum expected portfolio costs for varying levels of expected portfolio risk. The generation company has to make a trade-off in that, lower the expected cost higher the expected risk and vice versa as shown in the efficient frontier graph in Fig.3. The points on the efficient frontier A, B, C, D represent different generation mixes i.e. individual generation portfolios. \([14]\)

D. HPR at Risk – The Logical Schema

Holding Period Return (HPR) for technology ‘i’ is defined as

\[
HPR_i = \sum p_i HPR_i
\]

Where,

HPR\(_i\) (holding period return for the \( i \)th cost type, viz., fixed cost, variable cost and carbon compliance cost, etc. within technology ‘i’) is given by

\[| EV_i - BV_i | / BV_i\]

Where, \( EV_i \) and \( BV_i \) are the ending value (or values at the end of year \( t+1 \)) and beginning value (or value at the end of year \( t \)) respectively for the generating cost per kWh for the \( i \)th cost type within technology ‘i’.

The HPR at Risk Model Schema incorporating the carbon abatement cost is shown here.

Note that carbon abatement cost itself is one of the cost types that falls under each generation technology. The other cost types are capital expenditure, operating expenditure etc.

E. HPR at Risk Model Description

The primary objective of the model is to predict the probability that the HPR for a particular technology will not exceed a certain value for the current year (if the holding period is 1 year). The model can be configured to set the holding period at less than a year (quarter, month etc.) or more than a year. By convention, the holding period is 1 year.

The sequential mathematical procedures are simple. Monte Carlo technique is used to generate simulated “cost” stream (also called the forward path / future path) for each cost type within a particular technology. From each simulated forward path for a particular cost type, a forward path of HPRs of that cost type is obtained. The same process is iterated to all the other cost types within the same technology. HPR calculations are shown in the model schema. Finally, by aggregating the forward paths of HPRs of all the cost types within a particular technology, a forward path of HPR of that technology itself is determined. HPR of a technology is calculated in the model schema. The same set of iterative procedures is repeated for all the other technologies in the portfolio. Finally, the HPR at Risk for each technology in the portfolio are calculated from their respective HPR forward paths.

Fig 3 : Efficient frontier of generation portfolios
V. CONCLUSION

In the paper, it has been proposed that the future in generation portfolio optimization lies with a focus towards Combined Cycle Gas Turbine (CCGT) and linked financial measures such as FTR, HPR and Portfolio Theory with the physical portfolio of the generator. It is observed that FTR and HPR play an important role in deciding the generating portfolio together with the generation efficient frontier.

There are challenges like higher dependence on import of gas which in turn will be a concern for security of supply and FTRs auctioned price which off-sets some extent the hedging compensation that a generator earns from LMP differences during congestion. It should be noted that portfolio theory does not provide a single optimal generation portfolio but a set of optimal generation portfolios that have varying expected cost and expected risk combinations. The generator therefore has to make a trade-off between expected cost and expected risk while choosing a portfolio from this set of optimal portfolios. The paper leaves a scope for the future researcher to investigate all these challenges together with linking of financial instruments with physical portfolio of generator for addressing the climate challenge.

VI. ACKNOWLEDGMENT

The authors gratefully acknowledge the contributions of key personnel of Utility Group of Tata Consultancy Services Ltd., India and Electrical Engineering Department of University of Cape Town, South Africa.

VII. REFERENCES

[2] Ernst & Young, “Getting the balance right – the UK’s evolving generation mix An investigation of the implications of the energy white paper and the energy bill for development of UK’s future generation mix” – February 2008
[8] Ernst & Young “The European Generation Mix”
[9] Enrique De Leyva and Per A. Lekander “Climate change for European utilities”
VI. References


[12] João Catalão, Silvio Mariano, Victor Mendes, Luis Ferreira “Unit commitment with environmental considerations: A practical approach”


VIII. Biographies

Sanjay Neogi holds Bachelor of Electrical Engineering (BEE) and Master in Business Administration (MBA). Presently working with Capgemini as Associate Director in Energy & Utility group. Previously worked as a Utility CoE (Centre of Excellence) lead in Energy & Utilities Practice of Tata Consultancy Services Ltd. He has over eight years rich experience in IT consulting & implementation for utility industries in India & overseas and eight years industrial experience in power generation, transmission & distribution in various power utilities. Email: sanjayneogi@rediffmail.com

Anindya Pradhan holds Bachelor of Engineering (BE) in Power Plant and Post Graduate Diploma in Management (PGDM) with specialization in Strategy & Operation. Presently he is working as Business Consultant in Energy & Utilities Practice of Tata Consultancy Services Ltd. He has over ten years rich experience in Business consulting & IT for utility industries in abroad & India and also a Certified Management Consultant (CMC) from Institute of Management Consultant of India. (IMCI) Email: anindya.pradhan@tcs.com

Arup Sinha. holds Bachelor of Electrical Engineering (BEE) and Master in Business Administration (MBA). Presently working as a Utility Domain Consultant in Energy & Utilities Practice of Tata Consultancy Services Ltd, Kolkata. He has over four years IT experience in Consulting & Implementation for power Utility industries and over twelve years industrial experience in Power Generation & process plant. In addition to above he has good experience in Energy Auditing & Accounting and is a Certified Energy Manager & Auditor by Ministry of Power, Government of India. . He is a member of IEEE (USA), IET (UK). Email: arup.sinha@tcs.com

Dr. Sunetra Chowdhury received her BEE and PhD in 1991 and 1998 respectively. She was connected to M/S M.N.Dastur & Co. Ltd as Electrical Engineer from 1991 to 1996. She served Women’s Polytechnic, Kolkata, India as Senior Lecturer from 1998 to 2006. She is currently the Senior Research Officer in the Electrical Engineering Department of the University of Cape Town, South Africa. She became member of IEEE in 2003. She visited Brunel University, UK and The University of Manchester, UK several times on collaborative research programme. She has published two books and over 55 papers mainly in power systems. She is a Member of the IET (UK) and IE(I) and Member of IEEE(USA). She is acting as YM Coordinator in Indian Network of the IET(UK). Email: sunetra.chowdhury@uct.ac.za

Prof C.T. Gaunt received a BSc(Eng) from Natal University in 1971, an MBL (SA) with distinction in 1979 and a PhD (Cape Town) in 2003. He worked for 28 years with an electrical equipment manufacturer, electricity supply utility and consulting engineers, where he was a director. He is currently a Professor and Head of the Department of Electrical Engineering at UCT, but stands down from the HOD position at the end of 2008 to concentrate on teaching and research. He has received Best Paper awards from the Transactions SAIEE and the AMEU, a technology innovation award from Worldaware in UK, and a Cigré Technical Committee Award in 2004. He is the South African member of the Cigré Study Committee C6 (Distribution and Dispersed Generation). He has supervised several postgraduate students in DG research. He was the electrical engineer for the integration of and scheduling for several small hydro stations (6-72 MW) into grid operation in Southern Africa. Email: ct.gaunt@uct.ac.za

Dr. S.P. Chowdhury received his BEE, MEE and PhD in 1987, 1989 and 1992 respectively. In 1993, he joined E.E.Dept. of Jadavpur University, Kolkata, India as Lecturer and served till 2008 in the capacity of Professor. He is currently Associate Professor in Electrical Engineering Department in the University of Cape Town, South Africa. He became IEEE member in 2003. He visited Brunel University, UK and The University of Manchester, UK several times on collaborative research programme. He has published two books and over 110 papers mainly in power systems and renewable energy. He is a fellow of the IET (UK) with C.Eng. IE (I) and the IETE (I) and Member of IEEE (USA). He is a member of technical Professional Service Board of the IET (UK). Email: sp.chowdhury@uct.ac.za

Prof C.T. Gaunt received a BSc(Eng) from Natal University in 1971, an MBL (SA) with distinction in 1979 and a PhD (Cape Town) in 2003. He worked for 28 years with an electrical equipment manufacturer, electricity supply utility and consulting engineers, where he was a director. He is currently a Professor and Head of the Department of Electrical Engineering at UCT, but stands down from the HOD position at the end of 2008 to concentrate on teaching and research. He has received Best Paper awards from the Transactions SAIEE and the AMEU, a technology innovation award from Worldaware in UK, and a Cigré Technical Committee Award in 2004. He is the South African member of the Cigré Study Committee C6 (Distribution and Dispersed Generation). He has supervised several postgraduate students in DG research. He was the electrical engineer for the integration of and scheduling for several small hydro stations (6-72 MW) into grid operation in Southern Africa. Email: ct.gaunt@uct.ac.za