Final Report

Review of Electricity Price Setting Mechanisms

For

The Environment Bureau of the Hong Kong SAR Government

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Review of Electricity Price Setting Mechanisms

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EXECUTIVE SUMMARY

1 IPA Advisory Limited (IPA), formerly known as IPA Energy + Water Economics Limited**,** was commissioned by the Environment Bureau of the Hong Kong SAR Government (ENB) to produce a study of different price setting mechanisms (PSMs) commonly adopted in electricity markets around the world, as well as PSMs utilised by other local Hong Kong utilities, in order to understand their applicability to regulating Hong Kong's electricity market.

Hong Kong's current regulatory approach

2 The electricity sector has always been privately owned and operated in Hong Kong. The Government of the Hong Kong Special Administrative Region (the Government) currently regulates the sector through the Scheme of Control Agreements (SCAs). These SCAs allow the two incumbent utilities (i.e. CLP Power Hong Kong Limited and Castle Peak Power Company Limited (collectively: CLP); and the Hongkong Electric Company, Limited (HEC)) to recover all operating costs and make a maximum return of 9.99% on their average non-renewable net fixed assets (the permitted rate-of-return for average renewables fixed assets is 11%). The present SCAs are due to expire in 2018, and the Government is in the process of deciding whether alternative methods of regulating the electricity market could be more appropriate for Hong Kong in the post-2018 period.

3 The ENB is tasked with monitoring the power companies under the SCA regime, by assessing Development Plans (DPs) relating to the provision and future developments of the electricity supply systems of HEC and CLP to ensure the investments made are not excessive, premature and unnecessary. Each DP is subject to review and approval by the Executive Council. ENB also performs annual Tariff Reviews jointly with the power companies to ensure tariff adjustments are reasonable and to agree on changes from those approved in the Development Plans if applicable. In addition, an annual Auditing Review is also performed to monitor the financial, technical and environmental performance of the power companies.

Suitability of PSMs for Hong Kong post-2018

4 There are broadly four main PSMs for regulating prices and profits of utilities:

- **Rate-of-return regulation** – prices are set to cover the utility's costs of production and include a rate-of-return on capital that is sufficient to maintain investors' willingness to replace or expand the utility's assets;
- **Cap regulation** – establishes a diminishing price or revenue ceiling, reflecting expected productivity gains by the utility, and incentivises cost efficiencies as profits depending on its ability to keep costs below the determined cap;
- **Sliding scale regime** – a hybrid of the first two, where if profits rise above (or fall below) an agreed level then prices are adjusted downwards (or upwards) immediately so as to share some of the additional profit (or losses) with consumers; and
- **Yardstick regulation** – requires several firms operating in the market, and benchmarks them against each other to determine relative performance and efficiency, against which utilities are evaluated and remunerated.

5 The key strengths and weaknesses of each of these four PSMs in the context of the electricity policy goals of Hong Kong is summarised in the table below:

Suitability of different Price Setting Mechanisms in Hong Kong				
Hong Kong policy goal	**Rate-of-return**	**Cap regulation**	**Sliding scale**	**Yardstick**
Safety and reliability	✓ Incentives for investments help maintain current safety standards and reliability of supply	× Incentive to cut costs may result in reduction in safety and maintenance budget	× Increased risk profile due to variable rate-of-return decreasing attractiveness of investments	× Difficult to set with so few market participants
Affordability	× Tariffs linked to investment, which in theory could lead to higher tariffs, but can be mitigated through monitoring	✓ Tariffs may fall in real terms if efficiency gains are being made, given no changes in circumstances	✓ Incentives for efficiency gains, whilst protecting both consumers and companies from supernormal profits/losses	× Would not necessarily improve current tariffs due to lack of comparators
Environmental Impact	✓ Linking environmental targets directly with the rate-of-return can help achieve environmental objectives	× Requires additional incentive regulation and may increase regulatory burden	× Requires additional incentive regulation and may increase regulatory burden	× Requires additional incentive regulation and may increase regulatory burden
Source: IPA analysis				

Recommendations

6 IPA recommends that Hong Kong continues using its current rate-of-return regulatory framework post-2018. Given Hong Kong's need for secure supplies and its emphasis on reliability criteria, rate-of-return regulation provides the necessary incentives and protection from market risks. The current regime also helps to deliver Hong Kong's policy of reducing the environmental impact of the electricity sector, by incentivising performance in energy savings and conservation.

7 We suggest a few modifications to additional incentives to help meet Hong Kong's policy goals:

Allowed return on assets

8 We recommend continuing to derive the rate-of-return from a Weighted Average Cost of Capital (WACC) calculation. This is a commonly used method internationally, which would provide a justified and fair rate-of-return that would adequately cover the cost of capital of the companies.

Depreciation

9 Depreciation is allowed for fixed assets. These costs are non-controllable by the electricity companies, as the treatment of depreciation is clearly defined within the SCAs. We recommend that the current method of depreciation is applied in the new SCAs post-2018.

Operating Expenditure (Opex)

10 Under current SCA arrangements, Opex are passed through and ultimately borne by consumers. Opex items can generally be broken into two main categories:

- **Non-controllable Opex** – includes government rent and rates, insurance and fuel costs. This is outside the control of the electricity companies, and is therefore beyond the scope of this study.
- **Controllable Opex** – includes staff hires, materials and services. A fair price structure could be calculated by determining a starting pass-through cost based on historical costs, then subjecting it to an appropriate inflation index minus a productivity factor over the SCA period. However, apart from the difficulty in selecting an appropriate inflation index, this will only have limited impact on the tariff adjustment as controllable non-fuel Opex in Hong Kong currently constitutes only a small portion of the Net Tariff.

Fuel charging arrangements

11 Fuel costs account for a significant portion of the regulated tariff and have been the primary cause of tariff adjustments in recent years, mainly due to the replacement of long-term gas contracts upon expiry with new ones at current market prices which are much higher, coupled with the increased use of gas-fired generation to displace coal power plants for better air quality. The SCAs should ensure that the electricity companies are appropriately incentivised to procure fuel inputs at a competitive rate, and minimise volatility of fuel costs. In order to incentivise this, we recommend that the SCAs contain the following provisions:

- **Companies must demonstrate that fuel is procured economically** – companies must prove that they have procured fuel at a competitive market rate, for verification by an independent energy consultant. This form of regulatory oversight will ensure that companies are incentivised to minimise the cost of fuel and hence also electricity supplied to consumers. It is observed that measures have been taken in Hong Kong to ensure that companies demonstrate their fuel has been procured economically in the Tariff Review and Development Plan assessment, through the verification by independent consultant.
- **Companies should minimise their fuel cost volatility** – Companies may also be able to minimise fuel cost volatility through the purchase of long and short term forward contracts, or other means such as hedging. By reducing market exposure and uncertainty, hedging has both upside and downside risks and cannot guarantee a net benefit in fuel savings: if market prices increase more than expected, it will result in savings to consumers; conversely, if market prices fall greater than expected, additional costs will be incurred in the procurement of fuel. The administrative costs of hedging, from setting up future trades, broker fees and the formulation and implementation of a hedging strategy, need to be taken into account and considered against the benefits when deciding whether hedging is an appropriate choice for fuel procurement.

Environmental performance

12 In order to improve energy efficiency, demand side management or use of policies such as Revenue-neutral Energy Efficiency Feebates (REEF) would increase administrative costs but may improve the environmental impact of energy consumption in Hong Kong.

SCA duration

13 We recommend for the SCA duration to be kept at ten years with a regular review during the tenure. Although shorter regulatory periods may improve the ability for ENB to monitor and adjust the SCA where deemed necessary, reducing the regulatory periods will result in an increase in uncertainty for investors, thus raising the cost of capital. Balancing these considerations, we consider that the current regulatory period of ten years, with regular reviews during the term, should be appropriate.

Tariff approval mechanism

14 One possible SCA amendment is that Executive Council approval should be sought if the Net Tariff increase is more than a certain percentage compared to DP forecast. Imposing a requirement on power companies to explain significant fuel price discrepancy to the Executive Council should provide pressure on the companies to make more accurate fuel price forecast.

Reliability standards

15 Supply reliability is one of the obligations of the power company under the SCA. As such, the positive incentive adjustment of performance above the Average Service Availability Index (ASAI) target could be deleted. However, we recommend the penalty adjustment is maintained to ensure reliability performance, with the penalty level to be revisited based on recent actual performance.

Test for Excess Generating Capacity

16 The penalty for an additional unit of generating capacity failing the Test for Excess Generating Capacity two years in a row is that a 50% portion of the asset's mechanical and electrical equipment (M&E) costs will not attract Permitted Return for the shareholders of the companies, until it passes the test. This may need further consideration as, if the unit is deemed excessive, disallowing a higher proportion of the asset's M&E costs from earning Permitted Return may be more appropriate until it achieves the criteria to pass the Test for Excess Generating Capacity.

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GLOSSARY

Abbreviations Index	
Abbreviation	**Term**
AC	Average Cost
ACM	Authority for Consumers & Markets
AER	Australian Energy Regulator
ANFA	Average Net Fixed Assets
APC	Alabama Power Company
API	Appointment Punctuality Index
APSC	Alabama Public Service Commission
ASAI	Average Service Availability Index
CAGR	Compound Annual Growth Rate
Capex	Capital Expenditure
CAPM	Capital Asset Pricing Model
CCGT	Combined Cycle Gas Turbine
CCPI	Composite Consumer Price Index
CE-in-Council	Chief Executive in Council
CER	Commission for Energy Regulation
CESS	Capital Expenditure Sharing Scheme
CHP	Combined Heat and Power
CLP	CLP Power Hong Kong Limited and Castle Peak Power Company Limited
CNE	National Energy Commission
CPI	Consumer Price Index
CSPI	Connection and Supply Performance Index
CTB	Citybus Limited
DCF	Discounted Cash Flows
DEA	Data Envelopment Analysis
DECC	Department for Energy and Climate Change
DMIS	Demand Management Incentive Scheme
DNO	Distribution Network Operator
DP	Development Plan
DSO	Distribution System Operator
DTe	Office of Energy Regulation
EBSS	Efficiency Benefit Sharing Scheme
ECRF	Energy Cost Recovery Factor
ECT	Excess Capacity Threshold
EMA	Energy Market Authority (Finland)
EMA	Energy Market Authority (Singapore)
EMC	Energy Market Company Pte Ltd
ENB	Hong Kong Environment Bureau
EPO	Economic Purchase Obligation
ESB	Electricity Supply Board

Abbreviations Index	
Abbreviation	**Term**
FAA	Fare Adjustment Arrangement
FAM	Fare Adjustment Mechanism
FEPC	Fuel Price Stabilisation Fund
FEPP	Oil Price Stabilisation Fund
FERC	Federal Energy Regulatory Commission
GB	Great Britain
GSL	Guaranteed Service Level
GW	Gigawatt
HEC	Hongkong Electric Company Ltd.
HK	Hong Kong
IEA	International Energy Agency
IFI	Innovation Funding Incentive
IPA	IPA Advisory Limited
IPART	Independent Pricing and Regulatory Tribunal
IQI	Information Quality Incentive
ISO	Independent Service Operator
KMB	Kowloon Motor Bus Company (1933) Limited
KPI	Key Performance Indicator
LIPA	Long Island Public Authority
LOLP	Loss of Load Probability
LW	Long Win Bus Company Limited
MC	Marginal Cost
M&E	Mechanical and Equipment
MMHI	Median Monthly Household Income
MR	Marginal Revenue
MRA	Malta Resources Authority
MSSL	Market Support Services Licensee
MTRCL	Mass Transit Railway Corporation Limited
MW	Megawatt
NEM	National Electricity Market
NEMS	National Electricity Market of Singapore
NLB	New Lantao Bus Company (1973) Limited
NGET	National Grid Electricity Transmission
NO_x	Nitrogen Oxides
NPV	Net Present Value
NRFA	Net Renewables Fixed Assets
NSW	New South Wales
NVE	Norwegian Water Resource and Energy Directorate
NWFB	New World First Bus Services Limited
NYISO	New York Independent System Operator
NYPA	New York Power Authority
NYPP	New York Power Pool
O&M	Operating and Maintenance

Abbreviations Index	
Abbreviation	**Term**
OCGT	Open Cycle Gas Turbine
Ofgem	Office of Gas and Electricity Markets
Opex	Operating expenditure
PCR	Price Control Review
PES	Public Electricity Supplier
PF	Productivity Factor
PPA	Power Purchase Agreement
PSC	(New York) Public Services Commission
PSM	Price Setting Mechanism
RAB	Regulated Asset Base
RAV	Regulatory Asset Value
RC	Reserve Capacity
RCV	Regulatory Capital Value
RE	Renewable Energy
REEF	Revenue-neutral Energy Efficiency Feebates
RIIO	Revenue=Incentives+Innovation+Outputs
ROCE	Return on Capital Employed
ROE	Return on Equity
RPI	Retail Price Index
RSE	Rate Stabilisation & Equalisation
RSP	Respirable Suspended Particles
RV	Replacement Value
SAIDI	System Average Interruption Duration Index
SCA	Scheme of Control Agreement
SERC	South Eastern Electric Reliability Council
SHETL	Scottish Hydro-Electric Transmission Limited
SIC	Central Interconnected System
SING	Norte Grand Interconnected System
SIPCO	Consumer's Protection System for Fuel Excise Taxes
SO_2	Sulphur Dioxide
SPTL	Scottish Power Transmission Limited
STPIS	Service Target Performance Incentive Scheme
TAC	Transport Advisory Committee
TFP	Total Factor Productivity
TM	Technical Memorandum
TPE	Total Permissible Emissions
TSF	Tariff Stabilisation Fund
TSO	Transmission System Operator
TVA	Tennessee Valley Authority
USA	United States of America
USEP	Uniform Singapore Energy Price
USofA	Uniform System of Accounts
VAD	Distribution Aggregated Value

Abbreviations Index	
Abbreviation	**Term**
VIU	Vertically Integrated Utility
WACC	Weighted Average Cost of Capital
WAPC	Weighted Average Price Cap
WRACE	Weighted Return on Average Common Equity

1. INTRODUCTION

1.1 IPA Advisory Limited (IPA), formerly known as IPA Energy + Water Economics Limited**,** has been engaged by the Environment Bureau of the Hong Kong SAR Government (ENB) to produce a study of different price setting mechanisms (PSMs) commonly adopted in electricity markets around the world and by other local Hong Kong utilities, as well as their applicability to regulating Hong Kong's electricity market. As the present Scheme of Control Agreements (SCAs) are due to expire in 2018, the ENB would like to understand whether alternative methods of regulating the electricity market could be more appropriate for Hong Kong.

1.2 The scope of our services include a review of PSMs commonly used for power market regulation overseas, a review of PSMs used by local Hong Kong utilities, an evaluation of the strengths and weaknesses of each methodology and their suitability for the Hong Kong electricity market post 2018 and finally the provision of a recommendation as to whether any of the alternative PSMs studied would be superior to the current SCA regime, or whether there are any adjustments that could be made to the SCAs to improve consumer welfare.

1.3 This Final Report is set out as follows:

- **Section** 2**:** provides a high-level review of the economics of natural monopoly.
- **Section** 3**:** sets out PSMs used for power market regulation in terms of their theoretical strengths and weaknesses.
- **Section** 4**:** presents case studies of PSMs used in overseas power markets.
- **Section** 5**:** reviews PSMs used by other local Hong Kong utilities.
- **Section** 6**:** provides a high-level overview of the Hong Kong electricity market.
- **Section** 7**:** assesses the suitability of the PSMs for the Hong Kong electricity market.
- **Section** 8**:** sets out our recommendations for the regulatory structure of the Hong Kong electricity market.
- **Annex A:** provides an overview of the market liberalisation process.

2. THE PROBLEM OF A NATURAL MONOPOLY

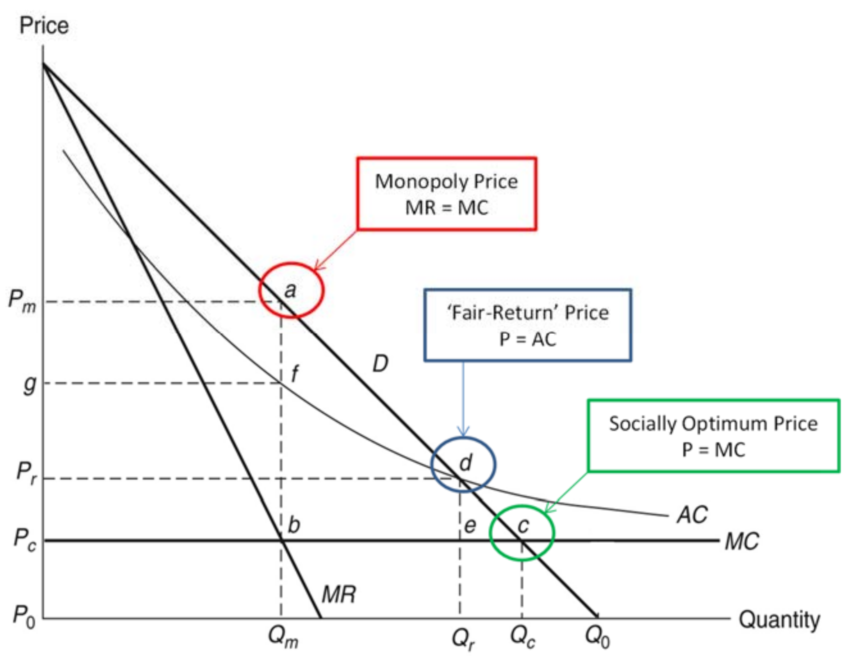
2.0 Natural monopolies tend to be associated with industries where there is a high ratio of fixed to variable costs. For example, the fixed costs of establishing a national power transmission or distribution network can be enormous, but the marginal (variable) cost of supplying extra units of output may be very small. In such a case, the average total cost will continue to decline as the scale of production increases, because fixed (or overhead) costs are being spread over higher and higher levels of output, but this average total cost will never be lower than marginal cost of the good itself. The result is that it is more efficient for one firm to serve the whole market rather than for several firms, giving rise to a natural monopoly.

2.1. Economic Theory

2.1.1 A natural monopoly is created and sustained by economies of scale over the relevant range of output for the industry. The scale of production that achieves productive efficiency will normally be a high percentage of the total market demand for the product in the industry.

2.1.2 To illustrate the problem, consider Figure 1, which illustrates a natural monopoly arising from economies of scale over the relevant range of production for a firm that is the only supplier of its product. The demand that this firm faces is therefore the market demand for its product, meaning that the firm must lower its price in order to sell each additional unit.

Figure 1: Diagrammatic representation of Natural Monopoly



Source: IPA analysis

2.1.3 The average total cost curve (AC) is shown to be everywhere declining (and hence the marginal cost curve, MC, is beneath the average total cost curve). Thus, any market structure involving several firms would involve the unnecessary duplication of fixed costs, meaning that it is more efficient for a natural monopoly to serve the whole market. Assuming that the firm can charge only a single price; that is, price discrimination is not allowed. If the firm is not regulated, it will maximise profits by opting to supply a product at a point where marginal revenue (MR) is equal to marginal cost, which represents the maximum output without incurring losses for each additional unit sold.[1] This quantity of production is output Qm, which can be sold at price Pm along the demand curve.

2.1.4 Productive efficiency, being the production quantity with the cheapest all-in production unit costs, requires producing and supplying at the minimum point of the average total cost curve. However, the market outcome in a natural monopoly does not satisfy this condition as this point lies beyond the demand curve. Allocative efficiency, which is where social welfare[2] is maximised, requires that firm produces and supplies a product where the marginal cost curve crosses the demand curve. This output is QC, which will be at the social optimum price, PC. However, the non-regulated market outcome again does not satisfy this condition due to natural monopoly, as detailed above. Relative to the social optimum, social welfare has been reduced by the triangle captured within points [a, b, c]; this loss of economic efficiency is called the deadweight loss to society.

2.1.5 Price regulation can theoretically lead to the social optimum if regulators specify that price be set equal to PC, where the c subscript denotes ‘efficient’. Then allocative efficiency is met. The outcome has moved towards productive efficiency; pure productive efficiency cannot be achieved simply because demand is not of sufficient magnitude for production to occur at the minimum average total cost curve. However, a firm that charges PC and produces at QC will not generate sufficient revenues to cover its costs of production; in particular, the firm will be short by the amount of its fixed cost. Thus, the regulator must alter the regulatory mechanism in order that the firm remains in the market. To ensure that the market is served, the regulator might offer the firm a subsidy equal to its fixed costs.

2.1.6 If provision of a subsidy is not politically feasible, the regulator may alternatively specify that the firm charge Pr, the price where the average total cost curve crosses the demand curve. At this price the firm charges the lowest price possible, subject to the constraint that it covers all of its costs. This regulatory mechanism increases social welfare by areas [a, b, d, e] relative to the market outcome. Society is still losing area [c, d, e] but this may be acceptable relative to the political cost of providing the firm with a subsidy equal to the firm’s fixed costs.

2.1.7 Alternatively, a firm may charge different prices for different amounts of the product purchased. A common approach to such a scheme, called a two-part tariff, is where each customer pays a monthly fixed price for access to the firm’s products equal to the total fixed costs divided by the total number of customers and then the customer pays an additional fee equal to the marginal cost for each unit consumed. The fixed fee covers the firm’s fixed cost of operation and the per-unit fee covers its variable costs. Since total revenues cover total costs, the firm would not require a subsidy. This pricing scheme is efficient only if consumer surplus, which is the value the consumer places on consuming the product less the cost the consumer must pay, is greater or equal to the fixed price paid by the consumer with the smallest demand. Otherwise some consumers will exit the market, in which case the scheme does not achieve the social optimum.

[1] Where there are profits to be made (i.e. MR > MC), then a profit-maximising firm will always try to sell extra goods. When MR = MC, this represents the maximum output where a firm can make a marginal profit. If MR < MC then the firm would be incurring losses for each additional unit sold.

[2] Social welfare = consumer surplus + producer surplus. Social welfare is maximised when everyone who is willing to pay above the cost of production of a good is able to purchase it.

3. REVIEW OF ELECTRICITY PRICE SETTING MECHANISMS

3.0 Economic regulation is an essential element of any electricity market, in particular for those sectors which are natural monopolies. The provision of electricity networks is by its capital intensive nature, a natural monopolistic activity. In order to facilitate fair and economic access to networks, transmission and distribution prices must be closely regulated. Economic regulation can also play a role in the absence of competition in generation and supply activities, as in Hong Kong at the moment, or as an interim measure to control prices while competition is introduced, develops and becomes effective.

3.1. Overview of Regulatory Frameworks

3.1.1 There are broadly four main methods of regulating prices and profits in utilities, namely the use of cap regulation, rate-of-return regulation, a sliding scale regime (which is a hybrid of the first two), and yardstick regulation, which benchmarks firms against each other to determine relative efficiency. Whatever method is used, the regulator must make an assessment of the total value of the capital assets employed by the utility, known as the Regulatory Asset Base (RAB)[3]. The RAB is normally used in calculating two important elements of the revenue requirements, which is the basis for the tariff calculation. The first is how to depreciate the asset base, which involves deciding the extent to which existing assets are already depreciated and by what accounting treatment assets should be written down going forwards. The second is determining an appropriate return on capital for the utility.

3.1.2 There are a range of different approaches for estimating RAB. One basic decision, for example, is whether capital assets should be valued at historic or current prices. However, in principle, assets included in the RAB should be the assets used for the provision of the regulated services that fall within the boundaries of the licensees operations. Assets financed by the public sector or end users should be excluded from the RAB.

3.1.3 The economics of regulation literature suggests that regulators are likely to face on-going difficulties arising from the inherent information asymmetries that exist in a regulated environment. Regulators do not have direct access to the firms' costs, revenues and assets or know their true cost of capital. Firms can therefore be expected to raise costs and inflate capital investment needs and the costs of raising capital during regulatory reviews, leading to a form of 'regulatory gaming'. As a result, effective regulatory incentives and regulatory governance regimes need to be in place. Moreover, there may also be a continuous threat from 'regulatory capture', which occurs when regulatory policies become over-influenced by the goals of the regulated firm or where the regulator is subservient to political interests and lobbying groups.

3.1.4 In effect, the job of the regulator is to provide the incentives for managers in regulated companies to maximise effort and reduce costs, while protecting consumers, and to minimise any additional profit that the company achieves by failing to reveal its efficient costs of production to the regulator. As mentioned above, there are a number of different models of economic regulation that they can employ to do this, namely:

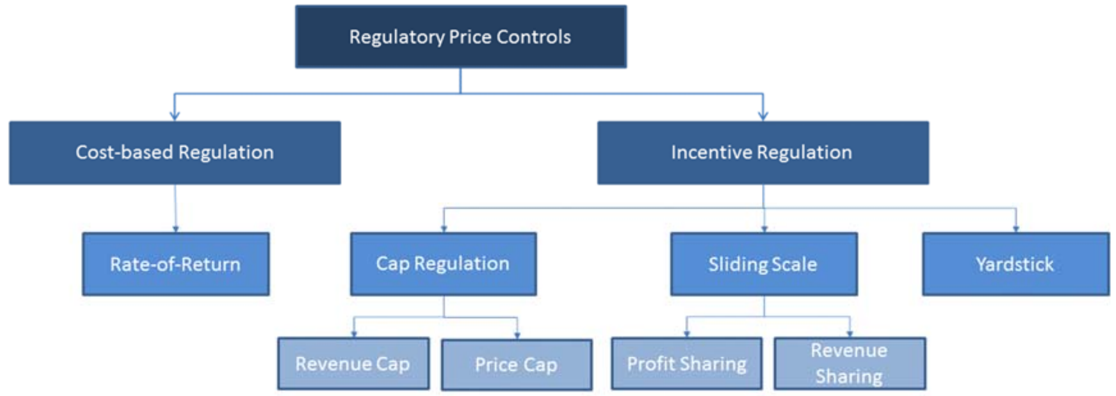
- Cost-based Regulation - Rate-of-return;

[3] Sometimes referred to as the Regulatory Capital Value (RCV) or Regulatory Asset Value (RAV)

- Incentive-based Regulation - Cap regulation;
  - Sliding scale; and
  - Yardstick (benchmarking).

3.1.5 However, there are many hybrids and variations within these broad categories and considerable variation in the sophistication of their application. Figure 2 below shows roughly how the different methods relate to each other.

Figure 2: Major price control models



Source: IPA analysis

3.1.6 In the remainder of this section we explain the various methodologies and discuss their theoretical strengths and weaknesses in context of:

- **Efficiency** – cost efficiency and regulatory burden;
- **Quality** – impact on investment and safety and reliability of electricity supply; and
- **Practicality** – regulatory capture and gaming, and tariffs stability and predictability.

3.1.7 The strengths and weaknesses of the PSMs are summarised in Table 1 below, and detailed in the subsections below.

Table 1:Summary of advantages and disadvantages of PSMs

Criteria	Rate-of-return	Cap regulation	Sliding scale	Yardstick
Efficiency				
Cost efficiency	×	✓	✓	✓
Regulatory burden	×	✓	×	×
Quality				
Impact on investment	✓	×	×	–
Safety and reliability of electricity supply	✓	×	–	–
Practicality				
Regulatory capture and gaming	×	×	✓	✓
Tariff stability and predictability (Regulatory risk)	✓	✓	✓	×

Note: The summary is reflective of theoretical PSMs, and does not reflect the rate-of-return regime in Hong Kong.
Source: IPA analysis

3.2. Rate-of-return

Overview

3.2.1 Under rate-of-return pricing, the regulator sets prices for the utility in such a way that they cover the utility's costs of production and include a rate-of-return on capital that is sufficient to maintain investors' willingness to replace or expand the utility's assets. Hence it is referred to as rate-of-return regulation. In the simple analysis presented in Figure 1 in Section 2, a competitive rate-of-return to the utility was built into the average total cost curve, as total costs must include an adequate return on investments. Thus, average cost pricing at P_r is an example of rate-of-return regulation, where the allowed rate-of-returns equal to the competitive rate-of-return. Rate-of-return regulation is widely practised in US in regulated industries. An example of a simplified formula for rate-of-return price control is set out in Equation 1 below.

Equation 1: Example Rate-of-Return Formula

$$R_t = C_t + D_t + T_t + (RAB_t * r_t)$$

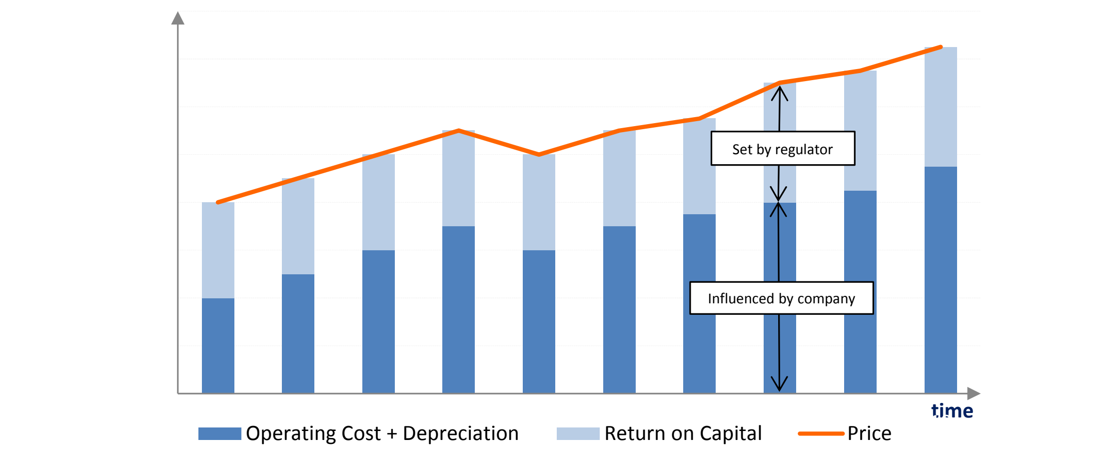
Required revenue in year *t*
Operating costs in year *t*
Depreciation in year *t*
Tax in year *t*
Regulated Asset Base in year *t*
Allowed rate-of-return in year *t*

Source: IPA analysis.

3.2.2 It shows that the allowed revenue in year *t*, is set equal to costs (operating and maintenance costs and depreciation), plus, an amount to give a reasonable return on the assets necessary to provide regulated services. The formula shows revenue for sake of simplicity. However, under rate-of-return regulation, the upper limit is often applied to prices, as opposed to revenue. Where a homogeneous product is produced, the upper limit to the regulated price could be obtained by dividing the allowed revenue by the projected number of units sold. The allowed revenue or prices are generally set every year or sometimes every two years.

3.2.3 Figure 3 shows how the price may evolve over time under rate-of-return regulation.

Figure 3: Example price evolution under rate-of-return regulation



Source: IPA analysis.

Regulation of a vertically integrated electricity utility – Malta

In Malta, the generation, distribution and supply of electricity is carried out by one vertically integrated company, Enemalta Corporation (Enemalta). The Malta Resources Authority (MRA), set up in the year 2000, is the main body responsible for the regulation and monitoring of the energy sector in Malta. MRA was set up as an autonomous regulator independent from the corporations that provide resources.

Supporting legislation

The Enemalta Act, Chapter 272 of the Laws of Malta, Article 20(3) stipulate that:

In prescribing tariffs, Enemalta shall ensure that the prices charged are adequate to provide sufficient revenue to Enemalta in any financial year:

- *to cover operating expenses, including taxes, if any, and to make provision for adequate maintenance, for depreciation, for interest payments on borrowings and for other interest payments;*
- *to meet periodic repayments on long term indebtedness to the extent that any such repayment exceed the provision for depreciation;*
- *to create reserves to finance a reasonable part of the cost of future expansion, being expenses, repayments and reserves incurred or made by the Corporation in the exercise of its functions relating to electrical energy; and*
- *to provide a reasonable return on investment and expenditure*

Price Setting Mechanism

Malta's electricity tariffs are based on a rate-of-return regulation. Tariffs are calculated on a 'full cost recovery' basis, which will enable Enemalta to recover all its acceptable costs and earn a reasonable rate-of-return on its capital employed necessary to enable it to meet its current and future debt servicing obligations as and when they fall due. The 'full cost recovery' method assumes that total variable retail tariffs should be equal to the sum of:

- Energy costs
- Wages
- Overheads
- Return on Capital Employed (ROCE)

After making the appropriate deductions and/or add backs in respect of

- Government subventions
- Fixed income charges
- Other services revenue

Enemalta's revenues are calculated over a six year period, with the current period being from 31 March 2014 to 31 December 2019.[4] As part of its review and approval process, MRA commissions consultants to review and test the information, assumptions and data used as a basis for the submission by Enemalta.

[4] http://mra.org.mt/wp-content/uploads/2014/03/5478/Minister-MECW-Approval-of-new-tariffs-for-supply-of-electricity-27.03.14.pdf

Advantages and Disadvantages

3.2.4 Table 2 below provides an overview of the main strengths and weaknesses of rate-of-return regulation.

Table 2: Rate-of-return

Evaluation criteria	Strength / Weakness
Efficiency	
Cost efficiency	✓ Removes opportunity to make "excessive" profits × No incentive to reduce costs as these can be shifted to consumers × Incentive to increase capital expenditure as return is a fixed percentage
Regulatory burden	- Medium/high information requirements × Setting of rate-of-return can be onerous due to scope for disputes × Reliance on regulator to ensure capital expenditure is not excessive
Quality	
Impact on investment	✓ Incentivises investment × Potential for over capitalisation / gold plating ✓ Lower cost of capital due to guaranteed rate-of-return
Safety and reliability of electricity supply	✓ Incentive for investment is likely to result in higher quality supply
Practicality	
Regulatory gaming	× Threat of companies taking advantage of regulatory regime as incentivises increased capital expenditure ✓ Low risk of discretionary intervention as prices are set according to costs
Tariff stability and predictability (Regulatory risk)	✓ Transparent and predictable ✓ Lower cost of capital due to guaranteed rate-of-return × Tariff varies according to level of investment

Source: IPA analysis

3.2.5 The primary advantage of rate-of-return regulation is that the level of profit earned by the utility is fixed at an acceptable level and there is no opportunity to make "excessive" profits. It is also low risk for the company because its revenues are set to recover all of its costs and a fixed level of return and so theoretically the company has access to a lower cost of capital than it would if its return were uncertain. Furthermore, company profits can be kept within acceptable levels from the perspectives of both investors and customers. Unless the regulator chronically underestimates the cost of capital, investors can be confident they have a fair opportunity to receive the profits they expect and thus are willing to make investments. Customers could observe that the regulator is limiting company profits through a fixed level of return.

3.2.6 While this form of regulation is simple in theory and could achieve feasible average cost prices, it has two major downside risks.

3.2.7 The first, referred to as the Averch-Johnson effect in the literature, is that it provides no incentive to control costs or reduce them. The utility knows it will be able to recover increasing costs with a subsequent increase in price in the following year. Provided that price reviews take place with sufficient frequency, the firm pays no penalty for inefficiency. Suppose the regulator tries to reduce costs by setting prices so that costs in real terms are a certain percentage lower than the previous year's costs. The utility has no incentive to make these costs savings since, if they are made, they are effectively immediately taken from the utility and given to consumers in the form of lower prices. The utility does not gain from efforts to reduce costs, as the allowed rate-of-return earned on capital is still the same. Hence there is no reward for the effort of holding costs down or reducing them.

3.2.8 The second main disadvantage is that rate-of-return regulation provides an incentive for the utility to over-invest in capital equipment and plant. Assuming that the rate-of-return is set at an adequate level, then by investing more and more in plant, equipment and other assets the utility will make a larger absolute return. This incentive to overinvest increases further if the utility is earning a higher rate-of-return than its cost of capital. This feature of rate-of-return regulation is sometimes known as “gold-plating”.

3.2.9 A regulator can try to identify this over-investment by inspecting investment plans, and hence prevent it from happening. Another method to mitigate against over-investment is to employ investment efficiency criteria, with checks to ensure that excessive capacity beyond the needs of the system has not been developed.

3.2.10 Further disadvantages in some cases include the need for frequent regulatory reviews and hence high associated costs for both the regulator and the regulated industry. For example, in the US, the level of regulatory scrutiny has escalated significantly, with utilities being annually cross-examined in public hearings (rate cases) by legal representatives of consumers and other stakeholders as well as the regulatory authorities in order to justify their operating and capital costs and practices. This approach therefore becomes a very resource-intensive form of regulation. In order to be fair to both sides, rate cases to adjust the allowed rate-of-return have to occur particularly frequently during times of high inflation unless the regulation has a periodic adjustment for inflation between rate cases built in.

3.2.11 There are further means to address the shortcomings of rate-of-return regulation. Examples of these are highlighted in country case studies in Section 4, and tools employed in the Hong Kong electricity sector are detailed in subsection 6.4.

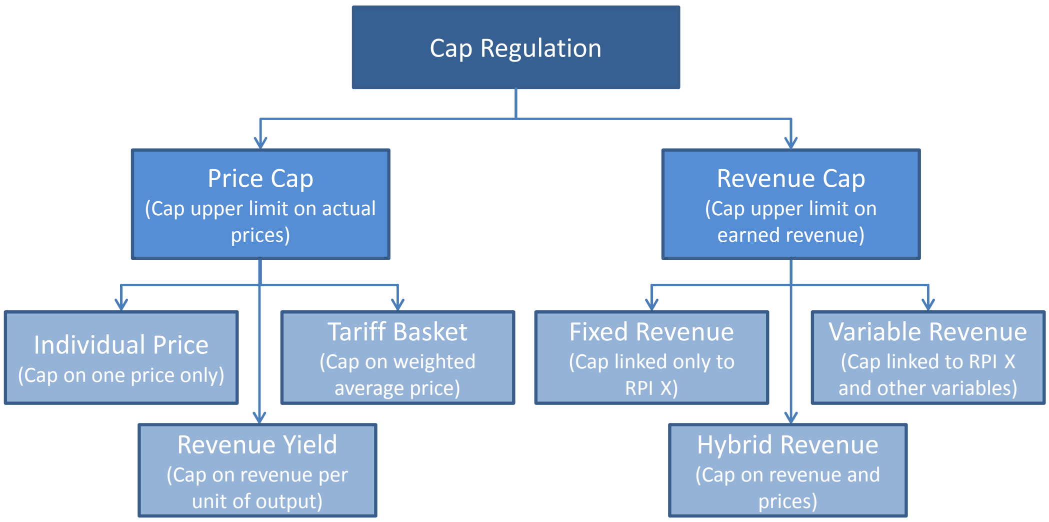
3.3. Cap Regulation

Overview

3.3.1 The cap approach to utility regulation, is perhaps the most widely discussed and significant innovation in utility regulation and alternative to rate-of-return regulation. The method was first proposed by Stephen Littlechild in 1983 and various versions of it have since been adopted in the regulation of infrastructure and utility industries in the UK and other countries. The main difference between cap regulation and traditional rate-of-return regulation is that under the former system, prices are no longer directly based on the company's actual costs. At the one extreme, under a pure rate-of-return scheme, prices would be set on the basis of the company's actual costs, which provide no incentive for the regulated firm to become more efficient. The other extreme is to completely unlink prices from actual costs, which provides very strong incentives for efficiency improvement. Cap systems are located somewhere between these two extremes. That is, prices and costs are detached from each other, but not to a full extent as there remains some interdependency.

3.3.2 Cap regulation establishes a price or revenue ceiling so that the profitability of the firm depends on the extent to which it is able to keep its costs below the determined maximum revenue under the cap. The cap can be initially set so that the forecast revenue will just cover the forecast operating and capital costs for the period to which the cap applies, and the firm may then reduce these costs while providing the agreed quality and quantity of service. The cap may also be set by calculating a maximum allowable return and setting an initial price and an X factor to ensure this maximum is not exceeded. Cap regulation therefore encourages productive efficiency and consequently is often referred to as 'incentive regulation'. The cap can be set in a number of ways. If, as is the case in Hong Kong, the electricity provider is a fully vertically integrated utility, the cap could be set on the individual components (e.g. generation, transmission, distribution, supply) or on the weighted-average price (i.e. a tariff basket) of the entire supply chain. Additionally, the cap could be set to limit revenue as a whole, or be set on a per customer basis. Figure 4 below provides an overview of the most common forms of cap-based regulation.

Figure 4: Overview of Cap-Based Regulation



Source: Commissioner Florin GUGU ANRE Romania (2004) *Methods for Price Control*

3.3.3 The big difference from rate-of-return is that under cap regulation, the price is set based on a level of cost that the regulator considers efficient, rather than on the basis of the company's actually incurred costs. The difference between actual costs and the regulatory estimation of efficient costs is reflected in the X factor. The X factor applies for a given number of years and determines the annual change in prices in such a way that prices move in line with the anticipated efficiency improvements. Equation 2 below shows the basic components of a price or revenue cap formula.

Equation 2: Example Cap-Regulation Formula

$$\text{Price Cap:} \quad \underbrace{P_t}_{\text{Price in year } t} = (1 + \underbrace{\mathrm{RPI}}_{\text{Retail Price Index (Inflation)}} - \underbrace{\mathrm{X}}_{\text{Productivity growth}}) * \underbrace{P_{t-1}}_{\text{Price in previous year}}$$

Revenue Cap follows same equation substituting Price (P) for Revenue (R)

Source: IPA analysis.

3.3.4 The length of the regulatory period, the level of the X factor and the measure of inflation are the key elements of the cap system.

3.3.5 Prices are adjusted for inflation because it is generally accepted that the cost of some inputs to the production process, such as equipment or labour, will change over time and that this change is not controlled by the utility. The inflation factor is typically a published index, most commonly the retail price index (RPI) or consumer price index (CPI).

3.3.6 Through the X factor, consumers directly benefit from efficiency improvements and cost reductions in the form of a lower price. On the other hand, the company will also benefit as long as it manages to reduce its costs in excess of the X factor. The residual cost savings can then be retained in the form of higher profits. If the regulator is able to accurately predict the company's future productivity improvements, it could set the X factor on this basis. Then, the company would not earn excess profits while at the same time, financial sustainability of the utility would also be assured. A better assessment of the company's true efficiency improvement potential can thus lead to better balance between the interests of the company and consumers.

3.3.7 Overall, the X factor should be low enough to leave the company with sufficient funds and it should be high enough so that consumers can also share the ongoing productivity gains. It is, however, the case that quantifying the productivity potential, and therefore setting the X factor, is seriously complicated by the regulator's sometimes poor informational position relative to the company. Generally, the utility will have private information about whether and by how much it could improve on its efficiency. This information is not available to the regulator and consequently, the regulator is constrained to compute the most appropriate X factor. Furthermore, the company could strategically exploit its superior informational position by talking down the X factor claiming for instance that it's based on inaccurate estimation and unrealistic or unattainable envisaged targets. Clearly, the regulator's ability to assess the company's true productivity improvement potential can greatly benefit the effectiveness of the cap system.

3.3.8 In practice the most commonly used approach to determine the X factor is the estimation of a regulated industry's total factor productivity (TFP) growth rate. TFP is representative of the productivity gains realised within an industry, often expressed as the portion of output not explained by the amount of inputs used in production. It must be measured against the TFP growth rate of the whole economy, after adjusting for any input price inflation to accurately reflect an industry's productivity growth rate.

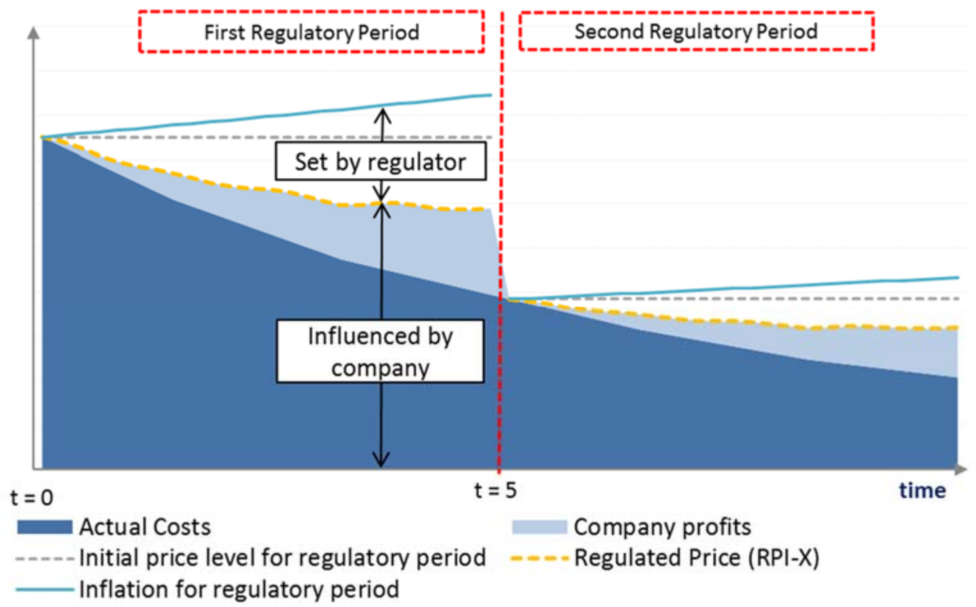
3.3.9 The intention of price cap regulation is to replicate competitive market conditions. For example, if a regulated industry is capable of achieving exactly the same productivity growth rate while facing the same rate of input price inflation as the competitive part of the economy, the X factor would be set at zero. Further, if a regulated industry is capable of increasing its productivity more rapidly than other industries of the economy and/or the input prices for the regulated industry increase less rapidly than the input prices for other industries' within the economy, the X factor would be set as a positive number.

3.3.10 Setting the X factor using an entire regulated industry TFP growth rate rather than each individual regulated company's TFP growth rates is generally considered more effective, as companies can then be rewarded for superior productivity performance against competing companies. Since a company can earn more profit if it can achieve greater productivity gains relative to the industry productivity target (or X factor), it has an incentive to be more productive than the industry as a whole, thus capturing further the essence of a competitive market.

3.3.11 Any change in the regulatory conditions may require that the X factor be modified, These include: structural change in the regulated industry; regulated industry prices becoming endogenous in economy-wide rate of inflation; a limited span of regulatory control over services in the regulated sector; and the presence of imperfect competition in the rest of the company will require that the X factor be modified. Failure to make modifications, which are often intricate, but generally intuitive can result in X factors that deviate significantly from their appropriate levels.

3.3.12 Figure 5 shows how the price cap and profit margin of the firm might evolve if the cap is set correctly and the firm achieves efficiency improvements over the control period.

Figure 5: Example price evolution under RPI-X regulation



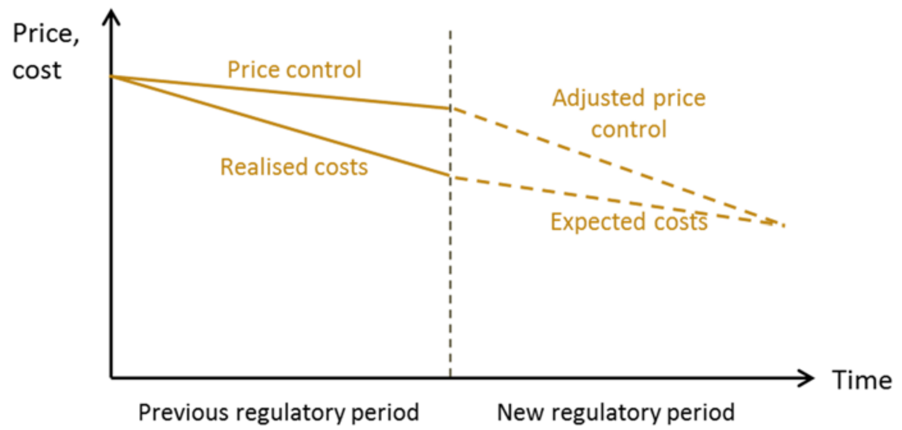
Note: Assumes that X>RPI, resulting in both a real and nominal reduction in price, although this may not always be the case. X may be set such that it is positive but lower than RPI, such that prices increase in nominal terms but decreases in real terms. A regulator may set X at less than 0, in recognition of the need for capital investment within a regulated industry, which would result in a real increase in price.
Source: IPA analysis

3.3.13 The length of the regulatory period is important because it is the period over which the company can benefit from any efficiency improvements beyond those factored into the X factor. The longer the regulatory period, the greater the company's rewards from efficiency gains. However, by limiting the duration of the regulatory period, the regulator can make sure that differences between actual productivity improvements and anticipated improvements are retained only for a fixed period before those gains are shared with consumers through lower prices. In practice, a regulatory period of between three and five years is generally considered to be reasonable compromise.

3.3.14 At the end of a regulatory period, prices can be adjusted to account for actual realised costs. However, one-off adjustments are generally not preferred as sharp fluctuation in prices and hence cashflows are difficult to anticipate and will affect the ability of companies to make sufficient returns to finance their investments, which in turn will affect their credit rating. One-off price reductions therefore weaken incentives. Furthermore, it is important to protect consumers from price shocks, especially in the event of incurred losses which might justify a rise in prices.

3.3.15 There is still a need to return prices to a level which is reflective of actual costs, so that companies are prevented from retaining levels of excessive profits and these efficiencies are returned to consumers. Instead of making a one-off price reduction, regulators in the UK generally prefer to set a path of projected prices such that the price control produces revenues that move smoothly towards the projected revenue requirement by the final year of the regulatory period, as illustrated in Figure 6 below. This ensures that incentives for regulated companies remain, as they retain some of the gains from out-performance in the previous regulatory period in the new review period, whilst allowing consumers to ultimately benefit from efficiency gains by the end of this period.

Figure 6: Smoothed revenue path between regulatory periods under RPI-X regulation



Source: IPA research.

3.3.16 The method applied by the British electricity and gas market regulator, Ofgem, has been to apply a correction factor (K-factor) to recover any over or under recovery of monies from the tariff process in the previous year, as detailed in Equation 3 below. This correction factor is calculated to allow the adjusted price control to reach the expected costs by the end of new regulatory period, as illustrated in Figure 6 above. This results in a steeper or shallower reduction of prices allowed under the price control, which should meet with the expected cost by the end of the regulatory period.

Equation 3: Example of a Correction Factor in a Rate-of-Return formula

$$\underset{\substack{\uparrow\\\text{Price in year } t}}{P_t} = (1 + \underset{\substack{\uparrow\\\text{Retail Price Index}\\\text{(Inflation)}}}{\text{RPI}} - \underset{\substack{\uparrow\\\text{Productivity growth}}}{\text{X}} - \underset{\substack{\uparrow\\\text{Correction}\\\text{factor}}}{\text{K}}) * \underset{\substack{\uparrow\\\text{Price in}\\\text{previous year}}}{P_{t-1}}$$

Source: IPA research.

3.3.17 Regulators in the UK have generally preferred not to weaken incentives by making one-off price reductions. When one-off reductions (or increases) have been made, this has generally been in response to particularly high profits (or losses) at the end of the previous period, with the implication that the firms have already received an adequate reward for the cost reductions.[5] Although this method eliminates excessive (or inadequate) revenues at the outset of the regulatory period, it weakens incentives for cost efficiencies, as detailed above.

Advantages and Disadvantages

3.3.18 Table 3 provides an overview of the main strengths and weaknesses of cap regulation.

Table 3: Cap regulation

Criteria	Strength / Weakness
Efficiency	
Cost efficiency	✓ Incentives to reduce costs permanently to increase profits in medium term ✓ Possibility for firms to increase profits by increasing their productivity and output × Risks of windfall profits if X-factor incorrectly chosen
Regulatory burden	✓ Low to medium information requirements ✓ Reduced monitoring of costs × It may require explicit cost projections with high administrative costs for setting of X-factor
Quality	
Impact on investment	× Potential for underinvestment – Investment impact / incentives depends strongly on the design × Likely higher cost of capital as firm bears higher profit risk
Safety and reliability of electricity supply	× Possibility of under-investment is more likely to result in lower quality supply × Requires supplementary quality regulation
Practicality	
Regulatory capture and gaming	× High threat of exploitation of information, incentive to inflate costs at the time the cap is set ✓ Low threat of regulator not acting in interests of consumer, typically long regulatory periods and burden is on company to make efficiency gain × High risk of discretionary interventions as profits from cost-savings might be seen as excessive by the general public
Tariff stability and predictability (Regulatory risk)	✓ Stable pre-defined regulatory periods – Less transparency required of company costs, but less intrusive

Source: IPA analysis

[5] EDI Development Studies (1999): *Resetting Price Controls for Privatized Utilities*

3.3.19 Cap regulation is typically applied to sectors which are natural monopolies such as transmission and distribution, with the aim of replicating competitive market conditions. It is more difficult for cap regulation to be applied to vertically integrated electricity companies, due to uncontrollable expenses such as fuel costs, although these items can be passed-through under a tightly-worded cap regime. When a sector can be liberalised and competition introduced, cap regulation (nor other PSMs) is no longer necessary.

3.3.20 Cap regulation minimises many of the deficiencies of rate-of-return regulation by weakening the relationships between actual costs and regulated prices. It avoids the need to frequently reset the regulated rates and provides greater price stability, due to having pre-determined regulatory periods, although is it still necessary to determine a suitable return on a RAB when setting the initial tariff.

3.3.21 Cap regulation is generally considered to be effective in incentivising companies to improve their efficiencies. By creating the possibility to increase profits by increased outputs and reducing costs, it incentivises companies to reduce costs permanently. These cost reductions are ultimately passed through to consumers at the beginning of the next regulatory period. However, cost reductions should not be achieved by prohibitive regulatory arrangements that would set an X factor which would not allow investors to earn an adequate rate-of-return (which is calculated as the beginning of each regulatory period, and subject to the issue of gaming by companies via submissions of inflated investment plans in the price review). In setting the caps, the regulator will need to ensure that X factor is sufficient to cover not only the efficient operation and maintenance costs, but also to provide an adequate return on the assets necessary to provide the regulated services.

3.3.22 Cap regulation can potentially enhance political commitment and reduce lobbying by regulated firms due to having pre-determined prices/revenues throughout each regulatory period. The original form of cap regulation by Littlechild was designed as a solution which would reduce regulatory burden, requiring mainly just a choice of regulatory period and a Productivity Factor. However, the picking of the Productivity Factor in practice has in some circumstance not been a quick process, often relying on benchmarking or calculation of anticipated productivity, and needing to take into account financing constraints of companies.

3.3.23 Despite the advantages of its strong incentive properties, one of the most significant unintended consequences of cap regulation is that its strong cost-cutting incentives tend to result eventually in lower levels of quality of supply. Theory suggests that cap regulation, without additional measures, eventually leads to degradation of reliability and other aspects of quality of supply. This is because the strong efficiency incentives, driven by the profit incentive, can have the perverse effect of encouraging sub-standard reliability levels in the medium to longer term. In simple terms, under cap regulation a utility can increase profits over a regulatory period by decreasing costs. Hence it will tend to reduce expenditure where possible, even at the expense of longer-term quality performance. Thus, under cap regulation systems, the inclusion of elements to regulate the quality of supply is imperative. A system of financial penalties for not achieving specific targets is often used. In addition, the price formula may include a parameter which links the revenue or price cap to a specified measure of the company's performance, often the company's performance in relation to a target quality level.

3.3.24 Sometimes it is argued that because of its strong cost-cutting incentives, the cap mechanism may not be the best choice for companies needing significant investment. However, this is not usually sufficient reason for not using cap regulation, as the cap can be set to take into account the need for investment. For example, when setting the cap, an allowance could be made to ensure that the cap will provide sufficient revenue to undertake the necessary efficient investment. Measures may also be needed to ensure that this investment is carried out. For example, in the UK water industry, the cap formula is "RPI - X + K", where K is based on agreed-upon capital investment requirements designed to improve water quality and meet EU water quality standards, although this has resulted in increases in the real cost of water bills.

3.3.25 Another disadvantage concerns the difficulties that can be encountered in determining reliable estimate of the scope of the regulated firm to make savings over the regulatory period. The success of cap regulation depends on how good an estimate the cap is of the efficient level of costs. In order to achieve this, because of the number of years for which the price control will apply, it is generally necessary (to minimise the need to re-open the regulations at a later stage) to consult reasonably extensively with the industry over the forecast revenue requirements and, for example, the scope for efficiency gains and sharing schemes before the price controls are implemented.

3.4. Sliding Scale Regulation (Profit / Revenue Sharing)

Overview

3.4.1 Lack of information about the firm's true productivity improvement potential may, as discussed earlier, lead to two basic problems. On the one side, the X-factor may be set too low and the firm will earn excessive profits. On the other side, the X-factor may be set too high, which can cause financial problems for the utility. Taking this into account, the regulator could decide to adjust the allowed revenue in such a way that the utility's profit varies only within a given range. Under this strategy, which is known as sliding scale, the regulator may adjust the allowed revenue as a function of the profitability of the utility (e.g. as measured in terms of its rate-of-return).

3.4.2 Sliding-scale regulation is something of a compromise between rate-of-return regulation and a price cap. Under sliding-scale regulation, a price cap is set and the firm has the usual incentives to raise profits by lowering costs of production. However, if profits rise above an agreed level then prices are adjusted downwards immediately so as to share some of the additional profit with consumers. In this way the level of excessive profits earned by regulated firms is restricted. Equally, the sliding-scale can be symmetric so that if the firm earns profits below an agreed level, prices are adjusted upwards so that consumers fund some of the revenue deficiency. Typically the regulator sets:

- a target range where no sharing arrangements apply (dead band);
- a wider range (above/below target) where sharing arrangements apply; and
- a maximum and minimum level of the sliding scale scheme.

3.4.3 A form of the sliding scale formula could therefore follow the example set out in Equation 1 below:

Equation 4: Example Sliding-Scale Formula

$$\underbrace{R_t}_{\text{Revenue in year } t} = (1 + \underbrace{\mathrm{RPI}}_{\text{Retail Price Index (Inflation)}} - \underbrace{\mathrm{X}}_{\text{Productivity growth}}) * \underbrace{R_{t-1}}_{\text{Revenue in previous year}} - \underbrace{\mu}_{\text{Sharing Parameter}} (\underbrace{\pi_{t-1}}_{\text{Actual profit in previous year}} - \underbrace{\pi^*_{t-1}}_{\text{“Fair” profit determined by regulator for previous year}})$$

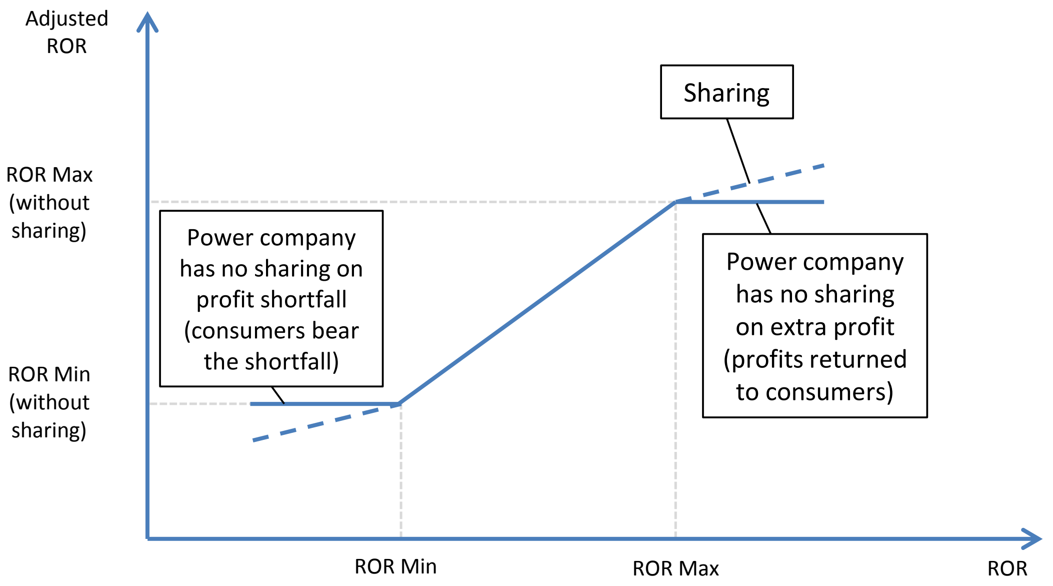
Source: IPA analysis.

3.4.4 If, at the end of the regulatory period, the firm's profit exceeds some predetermined band, the revenue is adjusted such that profits are brought back within this band. In other words, if actual profits are higher than the allowed maximum, the revenue is adjusted in such a way that these profits are reduced down to the level of the maximum. A similar procedure would also apply for the minimum profit level. In between the two extremes, the revenue would not be adjusted i.e. the firm would earn the rate-of-return as observed at the end of the regulatory period.

3.4.5 It is not uncommon for the sharing parameter to be set at 50:50 between the company and its customers. This ensures continued incentives for the company for cost efficiencies, whilst also immediately benefiting the consumer through reduced tariffs.

3.4.6 Optionally, the regulator can apply a sharing mechanism where the revenue is adjusted only partially in the case that profits exceed the predefined band. In that case, the firm would be allowed to keep a part of the profits achieved in excess of the maximum level. Conversely, if the firm earns less than the minimum profit, it would be forced to absorb part of the losses. Figure 7 below shows how a sliding scale mechanism may work both with and without sharing.

Figure 7: Sliding Scale regulation with and without sharing



Source: IPA analysis

3.4.7 Sharing usually takes place through adjustment of revenue in the next regulatory period.

Advantages and Disadvantages

3.4.8 Table 4 below provides an overview of the main strengths and weaknesses of sliding scale regulation.

Table 4: Sliding scale regulation

Criteria	Strength / Weakness
Efficiency	
Cost efficiency	– Medium incentives ✓ Revenues / profits resulting from cost reductions shared with customers ✓ Large sharing parameter → incentives close to Rate-of-Return regulation ✓ Small sharing parameter → incentives close to Cap Regulation
Regulatory burden	– Medium information requirements × Requires regular and reliable profit / revenue data
Quality	
Impact on investment	– Investment impact / incentives depends strongly on the design × In general weaker (than rate-of-return regime) incentives for investment
Safety and reliability of electricity supply	– Quality of supply dependent on the design × May require supplementary quality regulation

Table 4: Sliding scale regulation	
Criteria	**Strength / Weakness**
Practicality	
Regulatory capture and gaming	– Medium threat of information asymmetry, risk of manipulating profits ✓ Low threat of regulator not acting in interest of consumer, can implement sharing rule rather than intervene ✓ Low risk of discretionary intervention as profits are shared if they become "excessive"
Tariff stability and predictability (Regulatory risk)	✓ Transparent tariff regime ✗ Tariff not as predictable due to profit-based adjustment ✓ Risk and revenues shared between company and customers ✓ Reduced cost of capital due to more guaranteed rate-of-return
Source: IPA analysis	

3.4.9 Sliding-scale regulation is particularly useful where there is uncertainty about the costs that may be incurred by the regulated utility, perhaps where the utility has some ability to manage some costs but not others or where incentive regulation is being introduced for the first time. Its use can therefore add credibility to the regulatory regime in countries where there is a real likelihood that regulators will be captured and pressured to intervene whenever prices and profits rise or fall by more than expected.

3.4.10 Sliding-scale regulation can also reduce the threat of underinvestment. When the sliding-scale is symmetric, investors know that some compensation is automatically generated should there be an unanticipated change in costs or revenues that lead to financial losses. This can be important because of the 'hold up' problem which arises because utility industries involve high fixed costs. Once investors have made the investment to start production, presumably production will continue, even if loss making, providing that variable costs are covered. With variable costs appreciably lower than total costs in high fixed cost industries, investors understandably fear that regulators will act opportunistically and exploit the difference between variable and total costs, driving down revenues to variable costs. This threat of opportunistic behaviour by the regulator effectively increases risks to investors and therefore raises the cost of capital and forecast revenues needed to bring about the initial investment. Under rate-of-return regulation, this problem is reduced by the opportunity for the firm to demand a rate rebase, which is a complex process where the allowed return is recalculated to take into account long-term changes in business conditions such as the cost of capital as well as modifications in future investment plans in response to new laws or policies. However, under a price cap, it could be a serious weakness in the regulatory regime leading to under-investment. The sliding-scale can reduce, although not remove, the threat.

3.4.11 Sliding scale regulation also has the advantage that where prices are reduced, consumer demand will rise, dependent upon the price elasticity of the product, leading to more capital investment to meet the demand. The sliding-scale regime can therefore create investment incentives provided that new capital assets are allowed in the asset base for regulatory purposes and are allowed to earn a rate-of-return, and proper depreciation of these assets is allowed in annual costs to be counted as a pass-through expense. Moreover, sliding-scale regulation has the potential to provide both cost efficiency incentives to managers, while sharing any supernormal profits above a given level with consumers. This reduces the threat that regulators will be pressured by the media and politicians to intervene outside the agreed regulatory review periods, thus lowering the threat from regulatory capture. Profit sharing regimes do, however, require reasonably accurate accounts that reveal true economic profits. But the accounting requirements seem no more draconian than those required to set a price cap or to operate rate-of-return regulation.

3.4.12 The sliding scale strategy assures that profits remain within certain limits but also has the problem that it does not provide any strong incentives for the firm to perform in excess of these limits. The firm will not pursue any further productivity improvements once the maximum profit has been attained. In the case that sharing is applied, the firm only has limited incentives as it keeps only a fraction of the realised improvements. From the firm's point of view, additional improvements come at higher efforts but are not necessarily associated with any rewards. Similarly, the firm may well opt for the guaranteed minimum profit level (if this level is sufficiently high) rather than investing in productivity improvement. These problems become particular relevant in the case that the maximum and minimum of the profit range are set too low and high respectively.

3.4.13 Although sliding scale does in theory contain advantages over rate-of-return and cap regulation, there are few examples of it in practice within the electricity sector. This can be mainly attributed to the additional regulatory burden it will impose through what is essentially adding an extra layer of complication on top of the original regulation which, in reality, will be already extremely complex in practice by itself.

3.5. Yardstick Competition (Benchmarking)

Overview

3.5.1 Yardstick competition introduces a strong competitive aspect to the process of setting the X-factor. In the original definition of yardstick competition, suggested by Andrei Shleifer in 1985, the price for each company is set equal to the average cost of all other companies in the regulated industry. There are some variations on this theme. For example, the price can be set on the basis of the average cost of all companies (including the company under consideration), or one could apply some quantity weighted average of costs to calculate the yardstick price.

3.5.2 Each in a group of comparable regional monopolists has a price cap determined by the average cost of the others in the group. An example of a simplified formula for yardstick regulation of is shown in Equation 5 below.

Equation 5: Example Yardstick Formula

$$AC_i = \sum (AC_j) \ / \ (\mathrm{n}-1) \ , \qquad \mathrm{j} \neq i$$

Average costs of company *i*

Sum of all other companies

Average costs of company *j*

Number of all other companies in the market -1

j is efficient company within the market

Source: IPA analysis.

3.5.3 Irrespective of the specific formulation, the main idea is that the company's profitability is no longer determined only by its own cost performance, but is driven by how well it manages to reduce costs relative to others. This gives a strong incentive to increase performance, similar to the incentive observed in competitive markets. If a company manages to reduce its costs by more than the yardstick, it will earn a higher profit and conversely, companies that lag behind average performance will earn lower profits and possibly even incur losses. As all companies have an incentive to reduce costs, this also brings down the average cost within the industry. Thus, a continuous downward adjustment of the prices would take place whereby each company's effort to reduce costs in excess of the average simultaneously leads to a decrease in the yardstick itself.

3.5.4 The frequency of reviewing the average cost varies depending on regime. For example, in Chile the allowed revenues are reviewed every four years, whilst in Norway the cap is effectively calculated on an annual basis, although the main principles are re-evaluated periodically during a period lasting a minimum of five years.

Advantages and Disadvantages

3.5.5 Table 5 below provides an overview of the main strengths and weaknesses of yardstick competition.

Table 5: Yardstick competition

Criteria	Strength / Weakness
Efficiency	
Cost efficiency	✓ Strong incentives – Prices/revenues indexed to average cost/productivity improvement of industry ✓ Profits can be increased by reducing costs in relation to other companies
Regulatory burden	✓ Comparably lower information requirements × Does require a sufficient number of comparative firms whose data can be used to form the yardstick
Quality	
Impact on investment	× Potential of underinvestment – Investment impact / incentives depends strongly on the design
Safety and reliability of electricity supply	– Dependent on how tariffs are calculated prior to yardstick comparison × Requires supplementary quality regulation
Practicality	
Regulatory capture and gaming	✓ Low threat of information asymmetry, as costs are set by industry average – Medium risk of discretionary interventions if industry average is perceived as inefficient – Medium threat of collusion, incentive to inflate average industry costs at the time the yardstick is set
Tariff stability and predictability (Regulatory risk)	× Theoretically more transparent, but in practice complexities surrounding setting benchmarking mean accuracy is a concern ✓ Non-intrusive × Owners bear risk, process similar to competitive markets

Source: IPA analysis

3.5.6 In the price-cap context, the X factor under a yardstick competition scheme would be set on the basis of actual improvements in productivity. Thus, there is in principle no need for the regulator to make any predictions about productivity improvement potential as this information would be automatically revealed through the yardstick scheme. Also, as prices continuously track realised improvements over time, efficiency gains are quickly transferred to consumers. In essence, under yardstick competition the regulator would no longer have to set the X factor but would simply adjust prices each time on the basis of some index of average cost.

3.5.7 One potential drawback of yardstick competition is the need to adjust for possible structural differences between companies that are used to benchmark against each other, such as geographical constraints and population density. Setting prices on the basis of average costs suggests that companies are perfectly comparable to one another. This may not necessarily be true as there may be structural differences in the operating environment across companies. Some companies may have to deal with specific factors which lead them to incur relatively higher costs than others. Furthermore, one also needs to take into account the multi-dimensional nature of the company's production process. There may be more than a single input or output factor involved in providing the regulated service.

Neglecting such factors in the determination of the yardstick would disadvantage some companies and provide others with an unintended advantage. To deal with this problem, more sophisticated notions of average costs could be used. The use of benchmarking methods, which incorporate multiple input and output factors and allow to correct for structural differences, can play an important role in this process.

3.5.8 In addition to the comparability problem, there are two other main problems attached to yardstick competition, namely collusion and commitment.

3.5.9 The collusion problem is related to the fact that the companies may strategically cooperate to influence the outcome of the yardstick system. For example, companies may collectively report higher costs than actually incurred in order to drive up the yardstick. The fewer the number of companies, the increasing scope for collusion. Therefore, in order for yardstick competition to be effective, a large number of participating utilities is a necessary, but not sufficient, condition. Yardstick is traditionally only applied to companies within the same industry with similar operational costs, although conceptually a yardstick could be applied across sectors with similar back-office functions. This, however, would increase regulatory burden and increase complexity of setting a yardstick.

3.5.10 Yardstick competition assumes that the regulator is committed to the regulatory contract. This means that, irrespective of the outcome, the process by which the yardstick is calculated is not changed afterwards. In principle, this should also hold in the case of bankruptcy of one or more of the participating utilities. Similar to a competitive market, companies who perform better than the yardstick earn exceptional profits while others that lag behind will either earn less, or even potentially become unprofitable and eventually go bankrupt. If the yardstick system is to remain credible, bankruptcy of one or more companies should not be excluded as a potential outcome, implying that the regulator should not adjust the rules of the system ex post to prevent ill-performing companies from going bankrupt. However, bankruptcy of a major utility has substantial social and therefore political impacts. It therefore remains questionable what is the meaning of bankruptcy in this case and if such utilities would in practice be allowed to go bankrupt.

3.5.11 While yardstick competition is an important theoretical development in the economics of regulation literature, there are few cases of practical application with no pure model applied.

4. COUNTRY CASE STUDIES

4.0 In this section we present several case studies, documenting the experiences of a number of jurisdictions in their application of the various price setting mechanisms reviewed in Section 3. We provide a summary overview of the treatment of each of the electricity subsectors – generation, transmission, distribution and retail supply – and then provide a detailed assessment of the price setting mechanism used for the regulation of distribution system operators (DSO), followed by key lessons learnt.

Table 6 below summarises the countries studied and their regulatory mechanism.

Table 6: Simplified Overview of Country Case Studies

Case Study	Jurisdiction	Distribution Price Setting Mechanism (2014)
1	Finland	Rate-of-return
2	New York City (USA)	Rate-of-return
3	Alabama (USA)	Sliding scale
4	Chile	Yardstick
5	Norway	Revenue cap with yardstick
6	The Netherlands	Revenue cap with yardstick
7	Singapore	Price cap
8	New South Wales (Australia)	Price cap → Revenue cap
9	Great Britain	Revenue cap → RIIO

Source: IPA research.

4.1. Case Study 1 – Finland

4.1.1 The Finnish electricity market was liberalised for large customers in 1995 and for all customers in 1997. Finland is part of Nord Pool Spot, a multinational electrical power exchange for Northern European countries. Prior to 2005, the distribution and transmission networks were controlled by a light touch case-by-case regulatory regime. In 2005 Finland moved to a more intensive system of ex post rate-of-return regulation. The reasons for increasing the intensity of regulation were to provide incentives to improve cost efficiencies and to move away from case-by-case regulation which only sought to regulate companies which were suspected of overpricing.

Generation

4.1.2 In 2012, Finland had a generation capacity of 17GW, made up of primarily combined heat and power (CHP), nuclear and hydropower. It has no oil or gas reserves and relies 100% on import of fuels. Finland is looking to expand its nuclear capacity by 2016.[6] Within the wholesale market, electricity can be traded on the Nord Pool Spot, the physical power exchange of Nordic electricity market.[7] The generation market is a fully competitive liberalised market, which is fully interconnected with neighbouring countries.

Transmission

4.1.3 Electricity transmission has been legally and functionally unbundled from supply and generation. Fingrid is the monopoly responsible for high voltage transmission over the national grid. It is regulated by an ex-ante revenue cap model. A reasonable rate-of-return is decided by the regulator and the transmission system operator (TSO) sets the tariffs based on the regulator's decision. The TSO is obligated to compensate any surplus and allowed to recoup the deficit in their price setting in the following period.[8]

Distribution

4.1.4 At the end of 2010 there were 87 distribution companies and 12 high-voltage (regional) distribution grid operators. All distribution system operators (DSO) are for profit companies. The regulatory approach for the distribution sector follows an ex-post rate-of-return model, with quality regulation in the form of incentives for cost efficiency and the reduction of outages.

Retail Supply

4.1.5 There are 73 retail suppliers serving Finland's 3.3 million electricity customers. In the Finnish electricity retail market there are 4 electricity retailers with a larger than 5 per cent share of the market. Retail prices are fully competitive and are not regulated in Finland.

Regulation of the distribution sector

4.1.6 Price regulation is effected through control of the DSO's level of return rather than control of customer pricing. The decision made by the market regulator, the Energy Market Authority (EMA) concerning determination of the permissible level of return is in force for two sets of four-year regulatory periods (i.e. eight years). Decisions regarding whether actual adjusted return exceeds or falls below permissible reasonable return is given after each regulatory period.

[6] NordReg (2013)
[7] NordPoolSpot
[8] NordReg (2012): *Economic Regulation of TSOs in the Nordic Countries Report 4/2012*

Price Setting Mechanism

4.1.7 The permissible return of a DSO is effectively a rate-of-return regulatory model, calculated by means of a weighted average cost of capital (WACC) model which uses a fixed capital structure of 70% equity and 30% debt. This model does not impose any obligation on a DSO concerning its actual capital structure but is used in determining the permissible level of return, irrespective of actual debt to equity ratio.

4.1.8 The reasonable return ($R_{k,post-tax}$) in euros in year *i* after corporation tax is set according to the formula in Equation 6:

Equation 6: Rate-of-Return for Finnish DSOs

$$(R_{k,post-tax}) = \left[\left(C_{E,i} \times \frac{70}{100}\right) + \left(C_{D,i} \times (1 - t_1) \times \frac{30}{100}\right)\right] \times (D_i + E_i)$$

Where:

$(R_{k,post-tax})$	= reasonable return for company *k* after corporation tax in year *i*, euros
$C_{E,i}$	= real reasonable cost of equity in year *i*
$C_{D,i}$	= real reasonable cost of interest-bearing debt in year *i*
D_i	= adjusted amount of debt invested in DSO's operations in year *i*
E_i	= adjusted amount of equity invested in DSO operations in year *i*
t_1	= corporation tax rate in year *i*

Source: D&I Focus (2013): *Renewed Regulation of Finnish Electricity Distribution Networks*

4.1.9 According to the calculation formulae presented in the regulation, the reasonable cost of equity ($C_{E,i}$) and the reasonable cost of interest-bearing debt ($C_{D,i}$) are tied to the average interest rate of the Finnish government 10-year bond in May of the previous year. However, as the Finnish government bond yield has decreased in the last years, falling from 3.32% in May 2011 to 1.82% in May 2012 and 1.76% in May 2013, the permitted reasonable return for distribution companies has also come down to 3.19% in 2013[9].

Reasonable Return

4.1.10 Each year the EMA prepares a non-binding calculation of the distributions companies' reasonable return and actual adjusted return and notifies the companies. After the end of the four-year regulatory period, the EMA issues a formal decision determining the amount by which the DSO's actual adjusted return exceeds or falls below the permissible rate-of-return during the period.

4.1.11 In the case of excessive return, the EMA will require the DSO to lower its distribution tariffs during the following regulatory period by the excess amount, together with interest equalling the average reasonable cost of equity if the excess return is 5% or more. If the actual adjusted return is lower than the permissible reasonable return, the DSO is entitled to a corresponding increase of its tariffs during the regulatory period.

4.1.12 Incentives aimed at encouraging the distribution companies to maintain and develop its network and operations are set out in the regulatory framework. The DSO's performance relative to efficiency and quality of supply targets lead to an adjustment of the actual return, in order to adjust it to the permissible reasonable return. This adjustment

[9] D&I Focus (2013): *Renewed Regulation of Finnish Electricity Distribution Networks*

determines the amount by which the DSO can raise or lower its tariffs, together with interest equalling the average reasonable cost of equity, in the following regulatory period.

Treatment of RAB

4.1.13 The reasonable return is based on multiplying the regulatory asset base (RAB) by WACC. The value of the network is calculated by its net present value (NPV) instead of its book value, as this will not necessarily reflect actual market value of capital invested in the network. This NPV is calculated from the replacement value (RV) using component-specific unit price and age data. Lifetimes of network components are based on lifetimes chosen by network operators in the first regulatory periods, and vary between 5 and 60 years. The RV of the whole network is calculated by multiplying all the components with their respective unit prices.

4.1.14 An important part of calculation of the RAB RV of the unit prices of specific network components used in the determination of the network value are mainly based on unit prices presented in the network recommendation of Finnish Energy Industries (standard unit costs). Standard values are also defined for the buildings, sites, computer systems etc. invested in network operations. Standard unit prices are adjusted to correspond with the current value of money.[10]

Quality Regulation

4.1.15 Since 2008, incentives to improve quality of supply have been formally included in the economic regulation. This has come in the form of reducing reasonable return by a factor of any interruption costs incurred by customers. These costs are based on customer inquiry and are measured by the inconvenience caused by supply interruptions. In this scheme, annual customer interruption costs are compared with a reference value. This reference value is set independently for each DSO, and is an average of their actual four-year historical outage costs.

4.1.16 The difference between customer interruption costs and actual outage costs is halved to allow for atypical weather conditions and the limited ability of a network company influencing the occurrence of interruptions, and this amount may be deducted from the annual reasonable return of that company (at a cap of 20% of annual reasonable return)[11]. This scheme takes into account planned, unplanned, high-speed and delayed interruptions and re-closings.[12]

4.1.17 A company specific efficiency target was also established in 2008 using input-oriented efficiency benchmarking, in which the performance of the companies is measured against a frontier of companies performing best. Companies could improve their position on the frontier by improving operational costs, and a positive performance relative to these benchmarks leads to an increase in the allowed return, or a decrease for negative performance. This method is applied to reduce the performance gap among the companies, and uses the Data Envelopment Analysis (DEA) model to take into account individual operating environments for each company. This model is discussed further in the Norwegian Case Study.

[10] NordREG (2011): *Economic regulation of electricity grids in Nordic countries, Report 7/2011*
[11] Ibid.
[12] Tahvanainen (2010): *Managing Regulatory Risks When Outsourcing Network-Related Services in the Electricity Distribution Sector*

Fuel costs arrangements

4.1.18 There are no specific fuel cost arrangements in Finland. The liberalisation of the wholesale electricity market in Finland means that fuel costs are reflected in the wholesale electricity price to be taken up by end-consumers.

Key lessons

4.1.19 The underlying difference between rate-of-return regulation in Finland and Hong Kong is that in Finland regulation is made ex post. The choice by the EMA to determine actual adjusted return and permissible reasonable return after the four-year regulatory period using actual data, as opposed to determining allowable returns on an ex ante basis places substantial regulatory burden on DSOs as they are unable to prepare for any regulatory risk in a given period.[13] However, Finland's introduction of ex ante efficiency and quality of supply components reduce regulatory discretion, but at the same time allows for more high powered regulatory control.[14]

4.1.20 The risk of overinvestment is mitigated by the presence of efficiency benchmarking in the Finnish distribution sector. However, the use of operational costs as opposed to total costs (including interruption costs) in efficiency benchmarking transfers the choice of preferred efficiency target to the DSO. This is because improving interruption costs will have no impact on operational cost efficiency benchmarking. It is also a less accessible source for improvement than operational costs in the short term due to potential interruption costs improvements through network investment would occur over a longer time span than operational cost improvements.

4.1.21 Since 2005, the Finnish experience can be characterised by a maturing of regulation from a purely bottom-up approach, to one in which ex ante components have been established to increase the ability to incentivise efficiencies in quality of supply and cost efficiency, from which regulatory power is increased. The lengthening of the regulatory period from annual regulation to a four year period years since 1999 is also a signal of regulatory stability and maturation.[15]

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[13] Centre for Energy Policy and Economics, Swiss Federal Institutes of Technology (2007): *Benchmarking and Regulation in the Electricity Distribution Sector*

[14] Tahvanainen (2010): *Managing Regulatory Risks When Outsourcing Network-Related Services in the Electricity Distribution Sector*

[15] Ibid.

4.2. Case Study 2 – New York City

4.2.1 Electricity markets within the state of New York were liberalised in the late 1990s, migrating from the Vertically Integrated Utility (VIU) model of the New York Power Pool (NYPP), where power was provided by seven investor owned utilities in the state area to a liberalised market design with competition in generation and supply markets.

4.2.2 The key catalyst for change in market design resulted from the rising retail electricity prices, driven by overrunning nuclear power plant developments in the prior decade, as well as the signing of high-price long-term power contracts under the "Six Cent" electricity law enacted in 1981[16]. In 1999 the New York Independent System Operator, NYISO [17], was established serving as independent grid operator. This was also accompanied by the unbundling of the generation assets of the VIUs, leading to the establishment of a competitive wholesale electricity market.

Generation

4.2.3 Generation in the city of New York consists of 24 transmission connected generators, with capacity of 9.6 GW. Ownership of generation is split between private investor owned utilities and New York Power Authority (NYPA) a state owned utility[18]. Under the NYISO, generation units are able to contract bilaterally with suppliers as well as participate in the wholesale spot and day-ahead markets. Dispatch of plant occurs the basis of location based marginal pricing.

Transmission

4.2.4 High voltage transmission lines and substations within the city are owned and operated by the Con Edison Company of New York, with the NYISO responsible for the co-ordination of power flow across the state. Con Edison is regulated by the New York State Public Services Commission (PSC), responsible for the oversight of the revenue earned and conditions of service. Price control of Con Edison occurs through a "Rate Case process", analogous to rate-of-return regulation.

Distribution

4.2.5 The distribution network across the city of New York is owned and operated by the Con Edison Company of New York. The exception to this are the Rockaways in the 5th borough, where the distribution network is owned by the Long Island Public Authority (LIPA), which contracts for the network's operational and maintenance activities on a concessional basis[19]. Con Edison is regulated as a single entity, so its distribution businesses are subject to the same price control process as its transmission business. LIPA is responsible for setting the tariffs for the Rockaway distribution network.

Retail Supply

4.2.6 Following deregulation of the New York market, end users were now allowed to purchase their supply from any retail entity in addition to the incumbent utility Con Edison. Con Edison remains the largest supplier supplying 44% of total load (residential and non-residential load) and 40% of the total residential market[20].

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[16] NYISO
[17] Specifically the independent system operator is tasked with operation of the wholesale electricity market, high voltage transmission system as well as monitoring the reliability of the state's transmission system.
[18] The NYPA currently makes up 67% of the cities generation, owning 16 generators in the city.
[19] Maintenance and operational duties were handled by National Grid until 2013, where the contract was then awarded to the Public Service Enterprise Group (PSEG).
[20] New York Public Service Commission

Regulation of the transmission and distribution sector

4.2.7 As highlighted in the previous subsection, utilities in the state of New York are regulated through a process known as the "Rate Case". The purpose of the Rate Case is to determine the allowed revenue in order to earn a suitable rate-of-return for the utility to recover its costs of financing. There is no defined frequency for occurrence of the rate case; instead it is up to the utility to initiate this process through a submission of a "filing" to demonstrate the need for a tariff increase. The submission includes estimates of expenses (operating expenses, depreciation costs, taxes, a return on investor-provided capital and recognition of utility plant additions) and proposed Capex spend, from which the regulated asset base can be determined. Following the filing of a Rate Case, the PSC is then legally required to issue a decision within 11 months following its filing

4.2.8 Following the initiation of the Rate Case process by the utility, the PSC is tasked with the representation of the public interest, which initially begins with the review of the submissions and an investigation of the proposed changes to the current rate. The PSC is also then tasked with the development of an opposing position on the filing, together with an associated counter-proposal. This will include independent estimations of the utilities cost of capital, rate base, allowable depreciation and tax liability, such that the required revenue can be determined. The entire rate case process is overseen by an independent Administrative Law Judge, who ultimately provides recommendations to the PSC.

4.2.9 Following the development of the counter proposal by the PSC, testimonies from interested parties and utility staff are received, with a cross examination and rebuttal conducted by the utility. It is possible at any point within the review process for a settlement to be negotiated between the PSC and the utility, but this is still subject to the approval of the Administrative Judge. The issuance of a decision recommendation by the Judge is followed by public statement hearings held in service areas covered by the utility. The Commission then holds deliberations in public to resolve any outstanding issues necessary to determine the required revenue and end user tariffs. The agreed Rate Case for electric utilities remains in force over a term agreed by both the utility and the Commission[21].

Equation 7: Revenue Cap Calculation for Rate Case Process

$$Revenue\ cap = (Rate\ base \times Permitted\ rate\ of\ return) + Operating\ Expenses + Depreciation + Taxes$$

Source: IPA analysis

4.2.10 Equation 7 above highlights the process by which the revenue cap is calculated by both the PSC and the utility. The cost of capital is determined by the PSC and has varied historically between the Discounted Cash Flow (DCF) and Capital Asset Pricing Model (CAPM) approaches. A specific rate-of-return is agreed for each year of the Rate Case review period by PCS, taking into consideration the recommendations of the Administrative Law Judge.

4.2.11 Under the latest Rate Case, a return on equity (ROE) of 9.2% has been agreed on for electricity distribution, based on a common equity ratio of 48%. Any potential earnings above specified ROE thresholds up to 10.45% ROE are subject to 50:50 earnings-sharing between customers and the company. This increases to 75:25 for a ROE of 10.45%-10.95%, and increased further to 90:10 above 10.95% ROE.

[21] Under 2014 filings for the case of Con Edison, the electricity rate was agreed to cover duration to two years 2014-2015.

Quality Regulation

4.2.12 The PSC is responsible for compliance with conditions of service, safety standards and system reliability. Compliance is monitored through the use of Key Performance Indicators (KPI) by the PSC, of which the two most critical are:

- System Average Interruption Frequency Index – this measures the average number of interruptions per customer per year; and
- Customer Average Interruption Duration Index – this measures the average length of a customer interruption.

4.2.13 Reliability standards for transmission infrastructure are regulated by the Federal Energy Regulatory Commission, based on standards set by the New York State Reliability Council, a non-profit entity governed by the 6 TSOs, and enforced by means of penalties for non-compliance.

Fuel costs arrangements

4.2.14 Due to the liberalised nature of the generation sector, fuel costs are reflected in the wholesale electricity price to be taken up by the consumers.

Key lessons

4.2.15 Fundamentally the approach to utility regulation used in both Hong Kong and the City of New York are the same (ex-ante rate-of-return regulation). The key differences between the two countries result from their method of implementation. The introduction of a third party assessment into the regulatory process currently used in Hong Kong will have additional cost implications and will likely extend the price control proceedings, complicating the current process used by Environment Bureau of Hong Kong.

4.2.16 The state of New York is currently in the process of reforming the Rate Case process. This in answer to criticism that the current structure does not incentivise the necessary actions required to meet new policy objectives of supporting the growing development of distributed energy sources and technologies which enhance efficiency and demand elasticity of the market. The PSC, through its "Reforming Energy Vision"[22] initiative, if implemented would see distribution utilities function as aggregators and offtakers[23] of distributed generation. Suggested changes to regulatory framework related to price controls include:

- The transition from a rate-of-return with an annualised rate case to that of a longer eight year performance based rates and therefore stimulate longer-term capital investments, as they will be able to receive cheaper financing due to longer guaranteed returns on new investments;
- The development of incentives to pursue the development of distributed energy resources opportunities; and
- Amendment of current tariff rate structures to reward customer load responsiveness, to encourage off-peak loads, reduction of peak demand and demand-side management.

[22] New York State Public Services Commission
[23] Defined as Distribution System Platform Providers

4.3. Case Study 3 – Alabama Power Company (USA)

4.3.1 The Alabama Power Company (APC)[24] is a vertically integrated investor-owned electric utility. It is the largest utility in the state of Alabama and operates 12.2 GW of generation capacity, serving over 1.4 million customers in the state[25]. APC is the only electric utility in the state subject to Alabama Public Service Commission's (APSC) regulatory authority, with co-operatives and municipally run utilities being exempt from economic regulation, being typically operated as non-profit organisations. Regulation of the APC occurs via the Rate Stabilisation and Equalisation mechanism (RSE), implemented in 1982 following a number of years of consecutive and overlapping rate case filings by APC in order to recover costs incurred to meet growing demand over the period.

Generation

4.3.2 Regulation of the generation market is not within the regulatory scope of the APSC, due to the presence of a competitive market. The majority of generators in the state however are owned and operated by APC or other Southern Company subsidiaries. APC's 12.2 GWs of generation in the state is composed of coal (54%), nuclear (21%), oil and gas (16%) and hydro (8%). The remainder of power generation is met from power generated by the Tennessee Valley Authority's (TVAs)[26] 7 GW of generating capacity in the state (consisting of coal (31%), hydro (16%) and a nuclear (47%))[27], cooperatively and municipal owned generation and independent generators under power purchase agreements (PPAs) with APC.

Transmission and Distribution

4.3.3 The majority of the state's transmission and distribution network are owned and operated by APC, covering 44,500 sq. miles[25] or 84% of state. The remainder of the transmission and distribution coverage is provided by municipally and member owned cooperatives and the TVA. Both the TVA and the municipal and member owned cooperatives are operated as non-profit organisations, and thus are not subject the economic regulation under the APSC.

Retail Supply

4.3.4 As with transmission and distribution, APC is the incumbent supplier across the state with the remaining retail demand met by member and municipal cooperatives, which purchase wholesale power from the TVA[28] or have self-supply.

Regulation of the electricity sector

Price Setting Mechanism

4.3.5 Economic regulation of investor owned utilities is achieved through a form of sliding scale regulation based on rate-of-return regulation, known as the Rate Stabilization and Equalization (RSE). Under the RSE, the Weighted Return on Average Common Equity (WRACE)[29] for retail electric services is calculated annually, using projected revenues

[24] APC is the second largest subsidiary of the Southern Company electric utility.
[25] Alabama Power Company
[26] TVA is a U.S. Government owned non-profit utility.
[27] Tennessee Valley Authority
[28] TVA does sell power to energy intensive and industrial consumers and federal installations.
[29] Return of Equity is defined as the net income less preferred dividends divided by the common shareholders equity.

and expenses defined by the APSC[30] and in accordance with the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts (USofA). Submissions for the projected WRACE are required to be submitted by the 1 December of the year prior to review.

4.3.6 Under the current RSE regulation, APC is allowed to earn a WRACE between 5.75% and 6.21%. In the event that the ex-ante WRACE lies outside of the range, revenues are adjusted to the "adjusting point" of 5.98%.[31]. In the case of an adjustment to the rates, APC is required to submit detailed analysis surrounding the rationale for the adjustment to the APSC.

4.3.7 In 2013, the allowed return on equity ranges and associated adjusting point were adjusted to the current levels following a review via public proceeding. The review aimed to determine whether the prior WRACE band, which ranged between 13% and 14.5% was fair and reasonable. The proceeding resulted in the downward adjustment in the rates together an amendment of the RSE to include a self-executing mechanism to trigger a review of the allowed return. The self-executing mechanism is linked to the movement of the 30-year U.S. Treasury Bond rate, with a review of the allowed retail equity return band being triggered when the 12-month average 30-year Treasury Bond rate increases by more than 350 basis points or decrease by more than 200 basis points[32].

4.3.8 The Rate RSE also provides additional incentive based reward, in the form of an adjustment to the allowed rate of return in the event that APC is able to either:

- Retain an equivalent "A" grade credit rating, from a recognised credit agency; or
- Is ranked in the top third of the most recent customer value benchmark survey.

4.3.9 As of 2013 the incentive based return adjustment was set at 0.07%.

4.3.10 To ensure that rate increases do not result in significant step increases in retail tariffs, the rate RSE also includes provisions to limit the magnitude of tariff rises in the event of consecutive upward adjustments of tariffs. Tariff increases in any year are limited to ensure that the average tariff increase over any consecutive two periods does not exceed 4%. An absolute cap on tariffs is also in place, limiting the total tariff increase in any year to 5%.

4.3.11 The ex-ante approach used to determine projected WRACE can incentivise the over estimation of capital and operating expenditures and the underestimation of forecasting revenues. In order to protect consumers, the APSC requires that APC submits calculations of the actual WRACE for the previous period using historic data. In the event that this ex-post calculation reveals that APC's return was above the allowed rate of return, APC is required to refund retail customers sufficient revenue, such that its WRACE would then fall within the upper limit of the allowed equity return band. In the case where the opposite is true and the calculated ex-post return is observed to fall below the allowed equity band, no provisions are afforded to adjust revenues up to fall within the allowed band. This ensures that exposure to the financial risks associated with the forecasting of expenditures and revenues remains with APC, and therefore does not guarantee a return is made in the event of an ex-post earnings shortfall. Submission of profit sharing calculations and their review take place during the first quarter (March 1st) of the year for the preceding calendar year.

[30] As set out in Appendix B of Rate RSE, Alabama Power Company.
[31] The adjusting point is defined as the mid-point of the band.
[32] Alabama Public Services Commission 2013 Annual Report

4.3.12 The APSC RSE process is also supplemented with continuous review of expenses (O&M, administrative and general etc.) against a predefined timeline over the calendar year together with benchmarking of the respective expenses against comparable utilities to ensure their cost reflectiveness.

Tariff Calculation

4.3.13 In the event that the ex-ante projected WRACE does not fall within the allowed equity return band, adjustment of APC revenues occurs through the application of an 'RSE Factor' to tariffs. The methodology for the derivation of the RSE Factor is outlined in Equation 8 below.

Equation 8: RSE Factor ex-ante calculation

If the tax and retail adjusted common equity return exceeds the allowed upper bound equity return, i.e.

$$\frac{(r_{ap} - r_{rce}) \times \left(\frac{E_{retail}}{E}\right)}{(1-T)} \Big/ R_{retail} > L_{upper\ bound}$$

Then the following adjustment factor is subtracted from the specific retail tariff schedule:

$$\left((L_{upper\ bound} \times R_{retail}) \times \frac{BR_s}{BR_t}\right) \Big/ kWh_{total\ sales}$$

If the tax and retail adjusted common equity return falls below the lower bound equity return, i.e.

$$\frac{(r_{ap} - r_{rce}) \times \left(\frac{E_{retail}}{E}\right)}{(1-T)} \Big/ R_{retail} < L_{lower\ bound}$$

Then the following adjustment factor is added to the specific retail tariff schedule:

$$\frac{\frac{(r_{ap} - r_{rce}) \times \left(\frac{E_{retail}}{E}\right)}{(1-T)} \times \frac{BR_s}{BR_t}}{kWh_{total\ sales}}$$

Otherwise, no adjustment is made to the rate schedules in the respective review year.

Where:

r_{ap}	The adjusting point of the weighted equity return range, calculated as the mid-point of the upper and lower bound equity range plus any earned performance-based adder.
r_{rce}	Projected retail return on average common equity
E	Projected common equity as a proportion of the firm's capital structure
E_{retail}	Projected average retail common equity
T	Combined Federal (F) and State (S) income taxes, equivalent to (F+S-2FS)/(1-FS)
R_{retail}	Projected total electricity revenues from retail consumers
$L_{lower\ bound}$ and $L_{upper\ bound}$	Upper and lower bounds of the allowed equity returns
BR_s	Projected base rate revenue for a specific retail tariff schedule(s) in the review year, exclusive of tax and energy cost recovery rate (ECR)
BR_r	Projected total base rate revenues from all retail rate schedules in the review year, exclusive of tax and energy cost recovery rate (ECR)
$kWh_{Total\ sales}$	Total volume of energy sold (kWhs sold) by retail rate schedule for the review year.

Source: IPA analysis, Alabama Power Company

4.3.14 In the event that actual returns on equity are found to exceed the upper equity return bound, the ex-post profit is shared with consumers through the application of a 'Refund Factor', shown in Equation 9 below.

Equation 9: Refund Factor ex-post calculation

$$Refund\ Factor = \frac{\frac{(r_{arce} - L_{upper\ bound}) \times \left(\frac{E_{ar}}{E_a}\right)}{(1-T)} \times \frac{BR_{sa}}{BR_{ta}}}{kWh_{sj}}$$

Where

r_{acre}	Actual retail return on average common equity
$L_{upper\ bound}$	Upper bounds of the allowed equity returns
E_{ar}	Actual average retail common equity ($)
E_a	Actual common equity as a proportion of the firm's capital structure (%)
BR_{sa}	Actual base rate revenue for a specific retail tariff schedule (s) in the review year, exclusive of tax and energy cost recovery rate (ECR)
BR_{ra}	Actual total base rate revenues from all retail rate schedules in the review year, exclusive of tax and energy cost recovery rate (ECR)
kWh_{sj}	Total volume of energy sold (kWhs sold) by retail rate schedule(s) for the January following the review year.

Source: IPA analysis, Alabama Power Company

4.3.15 The calculated RSE and refund factors are added to individual retail rate schedules (tariffs) for the corresponding review year.

Treatment of RAB

4.3.16 Under the RSE, returns are earned on average retail common equity rather than a regulated asset base. The calculation of the average and projected retail common equity is carried out in accordance with accounting items defined in the FERC's USofA standards. In principle the total average retail common equity is calculated as:

Equation 10: Average Retail Common Equity calculation

$$\begin{aligned} &Average\ retail\ common\ equity \\ &= \left(\frac{Total\ electric\ investment \times retail\ investment\ factor}{total\ investment}\right) \\ &\quad \times \left(\frac{common\ equity}{Equity + Debt + preferred\ stocks}\right) \end{aligned}$$

Notes: The term "investment" is defined as the sum of historic costs power asset investment (current asset price + accumulated depreciation) in addition to non-utility property, fuel, materials and supplies and merchandise. The "retail investment factor" is defined as the proportion of "Total electric investment" attributed to the retail electricity sector.

Source: IPA analysis, Alabama Power Company

4.3.17 To arrive at the WRACE, the retail return on common equity is weighted by the ratio of the common equity to the total capital structure.

Equation 11: Retail Common Equity calculation

$$WRACE = \frac{Retail\ electric\ net\ income}{Average\ retail\ common\ equity} \times Retail\ common\ equity\ proportion\ (\%)$$

Where:

Total retail net income is calculated as the total electric retail operating revenue less the retail electric expenses [30].

Source: IPA analysis, Alabama Power Company

Quality Regulation

4.3.18 There is no specific monitoring of service quality apart from the implementation of the incentive based rewards in relation to customer value benchmark surveys. However the PSC does outline regulations regarding the adequacy of service, customer complaints and customer service requirements through the "General Rules of the Public Service Commission"[33], as well as the "Rules and Regulations for Electric Service"[34]. Technical regulations regarding the provision of electricity services are set out in the "Special Electric Rules"[35]. APC is also subject to reliability standards for bulk transmission assets, set at the federal level and enforced by the South Eastern Electric Reliability Council (SERC) Reliability Corporation.

Fuel costs arrangements

4.3.19 Fuel costs used in power generation are recovered from consumers through the application of Energy Cost Recovery Factor (ECRF) to all electricity tariffs on a quarterly basis. The calculation for the ECRF is shown in Equation 12 below.

Equation 12: Energy Cost Recovery Factor calculation

$$ECRF = \frac{Fuel\ costs}{Total\ energy\ sales\ (kWh)} \pm Correction\ factor$$

Source: IPA analysis, Alabama Power Company

4.3.20 In Equation 12 above fuel costs covers the quarterly billing period and include estimated fossil and nuclear fuel costs, purchased energy costs exclusive of capacity/demand charges, fuel hedging gains/losses and gains/losses associated with the sale of natural gas in electricity operations. This therefore means that consumers are exposed to losses/gains associated with fuel hedging. However, changes to the ECRF still subject to approval of the APSC, and is regularly reviewed as a part of the APSC's O&M monitoring. Total energy sales refer to the total kWh sold over the quarter and the correction factor is used to adjust over/under recovery of costs in the previous quarter. The ECRF is added to the individual retail rate schedules in addition to the WRACE.

[33] General Rules of the Alabama Public Service Commission, Alabama Power Company
[34] Schedule of Service Regulations and Rates for Electric Services in the State of Alabama, Alabama Power Company
[35] Special Electric Rules of the Alabama Public Service Commission, Alabama Power Company

Key lessons

4.3.21 The implementation of the RSE in the state of Alabama has provided a number of advantages over the traditional rate case arrangements currently used in other states (e.g. New York) as well as other traditional forms of regulation including:

- **Improved oversight**: through annual monitoring (as opposed to discretionary reviews in the case of the rate case) of the utilities return as well as on-going oversight or expenses and scrutiny of rate changes;
- **Mitigation of regulatory lag**: through the use of forecast data in determining the WRACE as opposed to the use of historical test year. This is also supplemented with the use of the recovery factor to incentivise the accurate forecasting of expenditures, though placing the financial risk of earnings shortfall with the APC; and
- **Smoothing of tariff growth:** through the limitations on the scale of rate increases.

4.3.22 However the principal disadvantage associated with this regulatory approach is that it drives the company toward the authorised WRACE, as opposed to a return appropriate to a specific utilities operational and financial risk.

4.4. Case Study 4 – Chile

4.4.1 The Chilean electricity market was one of the first to deregulate its electricity market, introducing competition in power generation, open access to the transmission network and yardstick competition on the distribution activity. Electricity reform in Chile has been greatly successful in lowering prices for end consumers since its inception in 1982.

4.4.2 There are two major interconnected systems in Chile, the Central Interconnected System (SIC) and the Norte Grand Interconnected System (SING) in addition to two minor electrical systems, Aysén and Magallanes. The public agency responsible for the sector is the Energy Ministry, which is responsible for plans, policies and standards regarding the development of the energy sector. The National Energy Commission (CNE), organizationally dependent on the Energy Ministry, is a technical agency responsible for studying prices and fixing tariffs according to applicable regulation through technical node pricing reports.[36]

Generation

4.4.3 Chile's installed capacity is 18.3GW and relies mainly on hydro-electric power, oil, gas and coal for generation. Privatisation and unbundling of the generation sector in the early 1980s to create a competitive wholesale market led to large scale private investment. As of 2012, capacity under construction and expected new capacity additions during the next decade total over 8.6GW, which will be more than sufficient in meeting projected demand growth.[37]

Transmission

4.4.4 Transmission networks are open access. Transmission facilities are remunerated through transmission tolls, paid 80% by generators in proportion to their use of the facilities and 20% by unregulated clients. Rates are designed for a 10% annual rate-of-return (adjusted for inflation) of the transmission assets' value. Operation, maintenance and administration costs are charged in addition.[36]

Distribution and Retail Supply

4.4.5 The two government transmission and distribution entities, Endesa and Chilectra, were privatised in the early 1980s. There are now eleven distribution companies, which sell electricity directly to end users. Prices within the distribution sector are regulated for all consumers with demand lower than 2GW, at a price determined using yardstick regulation.

Regulation of the distribution sector

Distribution Tariff Calculation

4.4.6 Retail tariffs for regulated end-consumers are set at the nodal price, which reflects the wholesale electricity price, plus the distribution aggregated value (VAD), which is the regulated cost of distribution.[36]

4.4.7 The VAD is set by the CNE for four year periods, and is based on costs for a model distribution company operating in a similar type zone (i.e. of similar density and urban/rural setting). It incorporates:

[36] http://www.centralenergia.cl/en/electric-market-regulation-chile/
[37] IEA - 2012 Chile Report

- Fixed costs for administration, billing and customer service expenses;
- Standard investment costs and operating and maintenance (O&M) costs for distribution per unit of power supplied; and
- Mean distribution losses in power and energy.

4.4.8 The indicated components are calculated for standard distribution zones, determined by the CNE and in deliberation with the companies. These standard zones represent distinctive distribution densities (high density, urban, semi-rural and rural).

4.4.9 In the traditional application of the yardstick competition mechanism, the regulation of monopolistic activities is determined through the comparison of costs and performance of similar companies or mirror companies or the reduced comparison of heterogeneous companies corrected for differences. In the Chilean regulation model, there is a hybrid-benchmarking scheme for different companies.

4.4.10 In this model, groups of companies of similar characteristics are compared with an efficient model company, identified through these standard distribution zones. Through direct comparison with a model company, efforts are made to provide an efficiency signal to similar companies of efficiency gains being made to ensure market wide efficiency gains. The regulation specifies that the cost study of the model company for each typical zone "will be based on an efficiency assumption in the investment policies and in the management of a distributing company operating in the country."[38] Thus, the model company is created based on company that works in a similar environment and which faces the same market restrictions. The efficient model company for each of the distribution zones is reassessed by the regulator every four to five years.

4.4.11 The methodology to determine the model company and the steps to be followed in the analysis can be essentially grouped in four stages.

- Collection and validation of information of the real company;
- Definition and dimensioning the efficient model company and its organisational structure;
- Determination of costs and their allocation to three fields (high voltage, low voltage and customers); and
- Determination of the VAD and the corresponding adjustment index to be used in the following four years, together with the identification of special circumstances.[38]

4.4.12 The global rate-of-return is set to a level between 6% and 14%, which is considered to be a fair range of rate-of-return for distribution companies operating within Chile. The pricing mechanism does not include either quality of service issues or financial penalties.

Fuel costs arrangements

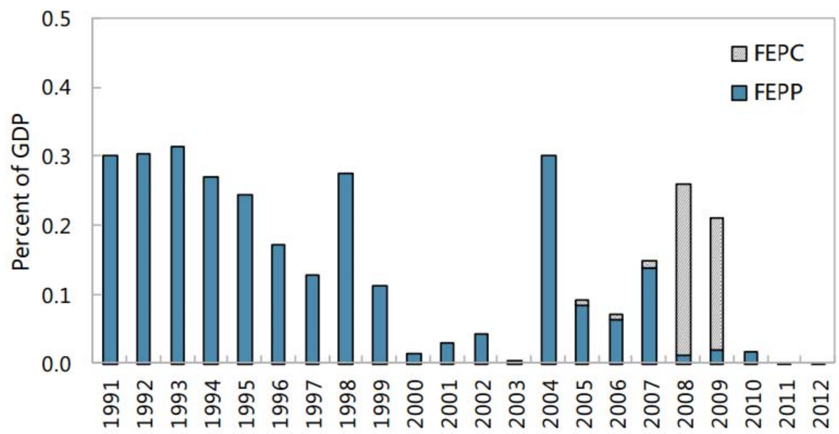
4.4.13 Following a spike in oil prices associated with the First Gulf War (1990-91), Chile established the Oil Prices Stabilization Fund (FEPP) with an initial fund of USD$200 million set up by the Government, which, with minor adjustments after ten years, worked successfully until its replacement in 2011. A temporary stabilisation fund was established in 2005, namely the Fuel Prices Stabilisation Fund (FEPC) as a response to price spikes

[38] Rudick and Donoso (2000): *Integration of Price Cap and Yardstick Competition Schemes in Electrical Distribution Regulation*

resulting from supply disruption during hurricane Katrina. This stopped operating in 2010 and both stabilisation funds were replaced by a tax adjustment mechanism.

4.4.14 The Consumer's Protection System for Fuel Excise Taxes (SIPCO) relies on excise taxes to smooth transmission of changes in international prices to domestic prices. The mechanism reduces excise taxes for fuel when international prices jump above a 10% band around a reference price and increasing excise taxes when international prices fall below the band. By focusing on excise taxes, this excludes large industries including electricity generators who can recover these taxes through deductions.[39]

Figure 8: Chilean Balance of Fuel Stabilisation Funds (1991-2012)



Source: Vignolo (2000): *The New Electricity Supply Industry in Argentina and Chile*

Key lessons

4.4.15 Assessment of efficient Distribution VAD is hampered by the legal specification of the assessment methodology. The process of assessing distribution VAD is currently restricted by the enforced use of an engineering model of the distribution system with no account being taken of the actual network cost or the comparative cost of other distribution networks or of data trends.

4.4.16 In practice data from the year of assessment is issued to calibrate the model company. This appears to have led to gaming by the companies who report higher costs in the year of assessment and whose consultant reports consistently document higher costs than the regulator's consultant reports. The calibration of the model company involves the assumption of a 10% real return on the new replacement value of the assets employed and involves the construction of an ideal company on the basis of actual demands and sources of supply. The overall price review can be reopened if the average return for the industry (electricity income only) is outside the range of 6 to 14% (it was 13.9% in 2002). However, the other income that the companies earn from leasing their lines to cable or telecom companies, does not count towards their regulated income thus leading to electricity customers paying for the full cost of the lines (this does not happen in the UK).

4.4.17 In theory the model company approach has appealing incentive properties in terms of making the revenue of the distribution company outside its control and giving it perfect incentives to reduce costs. However, the theoretical weakness of this system is that it

[39] IMF (2013): *Case Studies on Energy Subsidy Reform: Lessons and Implications*

relies heavily on the detailed structure of the benchmark model which may or may not bear any relationship to the reality of operating a distribution network in a particular environment. In practice additional distortion is introduced by the use of actual costs in the construction of the model company. The currently high rate-of-return of the distribution sector as a whole – much higher than in generation – suggests that the use of a model company is in this case excessively generous to the companies. If prices were reduced in order to bring the companies actual regulated rate-of-return down from its current 13.9% to 10% this might result in the VAD falling by over 10%.

4.4.18 The calculation and checking of the costs of the model company is a time consuming task and involves vast amounts of information being given to the regulator. Higher level techniques (such as data envelopment analysis, corrected ordinary least squares and stochastic frontier analysis) which involve analysing a few categories of overall cost in relation to a small number of outputs exist which substantially curtail the transaction cost and reduce the scope for gaming.

4.4.19 These techniques have been successfully employed in regulation in Norway, Australia and the UK. These models are more transparent and fair to the companies as they set regulated revenue with reference to the achieved costs in a comparator group of companies; they can also make good use of international data for the purposes of comparison. There is also a question mark about whether the VAD model is capable of being implemented for price that the CNE is allowed to pay. This was around $600,000 in 2000 which is less than one fifth of the figure for the UK distribution price control which involved fewer companies (14 as opposed to 34) and a less complex methodology.

4.4.20 In addition, the regulatory agencies face difficulties in obtaining the necessary level of detailed information from sector enterprises, particularly regarding costs, which may cause difficulties in their ability to perform effectively on issues dealing with pricing and competition.[40]

[40] Vignolo (2000): *The New Electricity Supply Industry in Argentina and Chile*

4.5. Case Study 5 – Norway

4.5.1 Norway's electricity sector was liberalised in 1991 following the Norwegian Energy Act, with full competition in the generation and retail supply sectors, and regulated monopolies in transmission and distribution. After Chile and the UK, Norway was one of the earliest countries to liberalise its electricity market, setting up the Norwegian Water Resource and Energy Directorate (NVE) as the sector regulator.

Generation

4.5.2 The Norwegian electricity wholesale market is part of the Nordic wholesale market through the common Nordic power exchange for physical power, Nord Pool Spot AS. This is a fully competitive liberalised market, with monitoring enforced through the Norwegian Competition Act to ensure there is no 'misuse of dominant position'.

Transmission

4.5.3 There is one TSO in Norway, Statnett SF, which is state owned and is unbundled from all other activities. Statnett is regulated through use of yearly revenue caps. This is based on 40 % of Statnett's own costs and 60 % of a cost norm, the latter of which is based on the results of the international study on the cost efficiency of TSOs in European countries.

Distribution

4.5.4 Norway has over 150 electricity distribution companies that are natural monopolies, each covering different geographical areas. Their revenues are regulated through use of a revenue-cap together with yardstick regulation. This method incentivises the reduction of costs, whilst comparing the performance of all distribution companies to determine the amount of revenue that they should be allowed to earn, and in doing so improve efficiencies.

Retail Supply

4.5.5 The supply market in Norway is competitive, with no regulated prices. Customers can choose their supplier, of which there were 118 licensed for supply to residential customers at the end of 2012[41] and are required to provide information on prices and contract terms. The Norwegian Competition Authority runs an official website for price comparison, which compares the three most common contracts of the market; about half of all residential customers have contracts which are presented on this website.

4.5.6 Most end users are customers of the incumbent supplier (the local network company), although this number has fallen over time. The market shares of the dominant suppliers averaged at 72% of residential customers at the end of 2012, although this varies from 19% to 97% within each grid area. Due to the wide geographic spread and low customer density of Norway, the dominant supplier within a network area is usually a vertically integrated supplier (providing generation, distribution and supply functions) or a supplier within the same corporation as the DSO. This is permitted under the Electricity Directive, where network and supply companies may be bundled in the retail market if the number of customers does not exceed 100,000.

[41]National Report – Norwegian Water Resources and Energy Directorate (NVE) 2013

Regulation of the distribution sector

4.5.7 Until 1996, rate-of-return regulation was applied, which reimbursed distribution companies with their reported costs and a market-determined rate-of-return on capital investments. However, due to lack of incentives for cost efficiency, since 1997 an incentive-based model of a revenue-cap with yardstick regulation has been used. This no longer guarantees full cost recovery but instead pre-determines a revenue cap, allowing for profits to be earned through cost efficiencies.

4.5.8 NVE does not determine each network company`s electricity distribution tariffs, but sets an upper limit for the revenue the company can recover from its customers. In accordance to the Energy Act Regulation, the main principles for calculation of the revenue cap are re-evaluated periodically, which each period lasting a minimum of five years. However, minor model adjustments can be made during the period, and some parameters are updated yearly. To this effect, revenue cap is calculated annually, which takes into account changes in CPI, interest rate on government bonds used in determination of the WACC and in power prices used to calculate costs related to network losses.

4.5.9 From 2007, a new regulatory model was implemented in which the revenue cap is comprised of 40% of the cost base (companies' actual costs that are effectively passed through, based on reported costs for year t-2), whilst 60% is based on cost norm using Data Envelopment Analysis (DEA) as an efficiency benchmarking method. This method of regulation is designed to incentivise the reduction of costs and the improvement efficiencies.

Equation 13: Revenue Cap calculation for Norway DSOs

$$Revenue\ Cap = (Cost\ Norm\ \times \beta) + \left(Cost\ Base\ \times (1-\beta)\right)$$

Where: $Cost\ Norm = Cost\ Base \times DEA\ Efficiency$

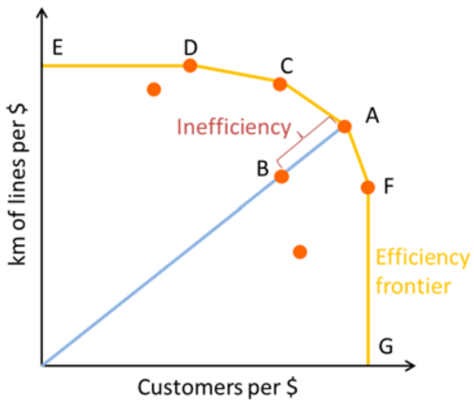
And: $\beta = 60\%$ under the current price control.

Source: IPA analysis

Data Envelopment Analysis

4.5.10 DEA has been used to measure the relative efficiencies of electricity distribution networks in a few European countries, including Germany, the Netherlands and Austria, as well as Norway. Companies are benchmarked on their distance from the efficient frontier (sector best practice).

Figure 9: Diagrammatic representation of Data Envelopment Analysis



Source: IPA analysis

4.5.11 Figure 9 provides an illustrative example of how DEA works when performance is measured against a single input (total costs) and two outputs (customer numbers and kilometres of lines). The efficiency frontier, given by the yellow line, is determined by the companies which provide the greatest outputs and the highest unit costs. The inefficiency of company B is determined by the distance AB, as company A provides a greater level of service in the form of more kilometres of lines and more customers for the same total costs

Treatment of RAB

4.5.12 Return of capital is a component of the 'cost base', used to calculate the revenue cap. This is calculated using the formula in Equation 14 below.

Equation 14: Calculation of Capital Costs for Norway DSOs

$$Return\ of\ capital = RAB_{t-2} \times WACC$$

Source: IPA analysis

4.5.13 The RAB is calculated from the book value (historic cost post-depreciation calculated on a flat-line basis over 30 years) at year t-2, plus a 1% allowance for working capital. Return of capital for each company is calculated using a WACC defined by NVE, which includes a risk free rate that is defined by the five-year government bond.

Quality Regulation

4.5.14 Separate quality of supply regulation was introduced in 2005, which included short interruptions which have been included in the DEA analysis since 2009. Quality adjusted revenue-caps were introduced in 2007, which factored in cost of energy not supplied, incentivising them to cut costs but not at the expense of quality.

Fuel costs arrangements

4.5.15 Due to the liberalised nature of the generation sector, fuel costs are reflected in the wholesale electricity price to be taken up by the consumers.

Key lessons

4.5.16 The revenue-cap with yardstick regulatory regime has been deemed to have worked relatively well in Norway, although a number of areas of improvement which have been identified, especially in light of the increase in renewables and the need for reinvestments in the existing electricity network, there are however a number of areas of improvement which have been identified:

4.5.17 **Complexity** – The DEA model used by Norway is complex with a large number of parameters and ex-post adjustments, such as for environmental factors, calibration and deviation corrections.

4.5.18 **Potential cashflow shortage** – Due to the cost base being based on reported costs in year t-2, a substantial part of the cash flow will be recovered late in time which could have adverse impacts on available capital for planned investments.

4.5.19 **One year reference period** – As the DEA is based on a single year of reported costs, large investments in any particular year will therefore impact the efficiency score of that company. This is particularly relevant to the regional grid model, where investments are irregular.

4.6. Case Study 6 – The Netherlands

4.6.1 The Netherlands' electricity market ranks among the leading International Energy Agency (IEA) member countries in terms of market integration, ease of entrepreneurship, investment and innovation. The Netherlands has a fully unbundled electricity market, and the entire market is regulated by the Authority for Consumers and Markets (ACM).[42]

Generation

4.6.2 Power generation in the Netherlands is dominated by gas-fired generation and coal generation. The market for generation is fully liberalised[43], and the market can be deemed to be moderately concentrated, with the 3 largest companies representing 59% of power generation in 2009 (latest available data).[44]

Transmission

4.6.3 Tennet is the national transmission system operator (TSO) for electricity, and is fully owned by the Dutch state. It is regulated by the ACM under a revenue cap, with a yardstick that is partially based on an international benchmark or best practice, combined with a frontier shift based on productivity growth of other foreign TSOs.

Distribution

4.6.4 Distribution in the Netherlands is provided by ten regional companies owned by the Dutch government. These companies regulated by use of revenue cap with yardstick competition – a hybrid model of regulation[45].

Retail Supply

4.6.5 The Dutch retail market is relatively concentrated with about 80% of retail supply held by Electralabel, E.On Benelux, Essent and Nuon. It is a liberalised market and is seen to be operating well with satisfactory switching rates and active competition for end-users.[46]

Regulation of the distribution sector

4.6.6 The Electricity and Gas Acts in the Netherlands specify that the regional gas and electricity networks in the Netherlands be regulated under a revenue cap with yardstick competition. The general principle of a yardstick regime is that a single price control is set for the industry. As a result, each of the ten regional DSOs face the same X-factor, which stays the same in each year of the price control period.

Price Setting Mechanism

4.6.7 A uniform productivity factor is currently set for all companies based on industry average performance. This is measured as the change in Total Factor Productivity (TFP) of the industry. The yardstick formula is defined in Equation 15 below.

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[42] Nova Workboard *(2014): The Unbundled Electricity Market in the Netherlands*
[43] Janssen, Pigmans & Brinkman (2009): *Getting the Deal Through: Netherlands*
[44] European Commission (2011): *Netherlands Energy & Gas Markets*
[45] Hesseling & Sari (2006): *The introduction of quality regulation of electricity distribution in The Netherlands*
[46] *European Commission (2007): Netherlands Internal Market Fact Sheet*

Equation 15: Yardstick Formula for the Netherlands

$$AR_{t,i} = AR_{t-1,i} * \frac{1 + CPI - X + Q}{100}\%$$

Where:

$AR_{t,i} = Allowable\ Return\ (€)$

$CPI = Consumer\ Price\ Index$

$X = X\ Factor$

$Q = Q\ Factor$

Source: Frontier Economics (2012): *Trends in electricity distribution network regulation in North West Europe*

X-Factor

4.6.8 The Office of Energy Regulation (DTe) sets a uniform X-factor for each of the ten DSOs in the industry. The X-factor is calculated by using a TFP approach, which is an approach that calculates the average of the ratio of standardised inputs and outputs of each of the firms.

4.6.9 The standardised inputs used in the calculation of total factor productivity growth represent standardised economic cost. This consists of:

- A return on a standardised asset base (WACC times standardised asset value); plus
- A depreciation allowance based on the standard asset value; plus
- Operating costs (including costs for distribution charges).

4.6.10 The standardised output used in the calculation of total factor productivity growth is a composite output variable. It is calculated as a sum of all the services in the tariff baskets (for example transported kWhs and reactive power) charged to consumers, weighted by average sector prices in the base year. The composite output is a weighted sum of:

- The amount of annual transport fees;
- Peak demand;
- Contracted demand;
- Generation (peak and base);
- Reactive power; and
- Annual connection fees.

Q-Factor

4.6.11 In 2005, DTe introduced a form of quality regulation into its determination of the price cap in the electricity sector. The so-called Q-factor is intended to reduce the incentive to companies to reduce costs at the expense of quality of service.

4.6.12 The quality factor allows for an adjustment to each company's tariff basket to reflect quality performance in the previous period. The adjustment is symmetric, in the sense that a company that outperforms will receive an increase in allowed revenues and a company that underperforms receives a decrease in allowed revenues. DTe imposed boundaries on the size of adjustment of +/- 5% of total revenue in a given year. Performance is measured in terms of the monetary value that customers place on interruptions (SAIDI), which is determined by dividing the total duration of the interruption in minutes by the total number of connected customers.

Treatment of RAB

4.6.13 Capital costs represent an important part of total costs. However, DTe argues that simply collecting the reported capital costs from company accounts might bias any comparative analysis, as some differences in reported capital costs are likely to arise from the use of different accounting policies (e.g. assumed asset lifetimes, choice of depreciation methodology etc.). DTe therefore requires a standardised annual capital cost constructed by applying the same accounting rules to the investments made by each company. This involves:

- Using the same depreciation life time for a given asset type;
- Using straight-line depreciation methodology;
- Allowing the same rate-of-return on standardised asset value; and
- Treating intangible assets in a consistent way.

4.6.14 The standardised asset base is then included in the calculation of the output:input ratio as part of the TFP approach to setting of the X-factor.

4.6.15 The return on capital is calculated by applying a WACC to the standardised asset value. A real pre-tax WACC is calculated as the weighted sum of the cost of equity and the cost of debt, where the weight on equity is equal to the level of gearing and the weight of debt is equal to one minus the gearing level. A Capital Asset Pricing Model (CAPM) is used, which assumes that investors have to be compensated for systematic risks (market risks), while non-systematic risks (company-specific risks) may be diversified and do not warrant an additional risk premium.

4.6.16 A straight-line depreciation allowance is calculated for the standardised asset value using assumed useful lives for different asset classes. The useful lives vary from five years for IT equipment to 50 years for connections to the grid. The asset value itself assumes similar approaches to the valuation of assets and the standardisation of depreciation periods.

Fuel costs arrangements

4.6.17 There are no specific fuel cost arrangements in the Netherlands. The liberalisation of the wholesale electricity market in the Netherlands means that fuel costs are reflected in the wholesale electricity price to be paid for by end-consumers.

Key lessons

4.6.18 A number of lessons can be taken from the regulation of the electricity distribution sector in the Netherlands. These include:

4.6.19 **Treatment of outperformance creates strong efficiency incentives:** Company outperformance relative to average industry performance is not clawed back by the regulator. This provides strong efficiency incentives.

4.6.20 **Distortions are reduced by the use of standardised cost bases:** This helps smooth out differences in asset valuation policies, and creates comparisons on a more like-for-like basis.

4.6.21 **Total cost approach accounts for trade-offs:** Trade-offs may arise between operating and capital expenditure levels, and any potential accounting concerns relating to the capitalisation of operating expenditure. A total cost accounts for these trade-offs.

4.6.22 **Light touch approach:** Minimised bureaucratic involvement by the regulator in the managerial decisions of the business.

4.6.23 **Quality regulation:** Reduces the incentive to companies to reduce costs at the expense of quality of service.

4.7. Case Study 7 – Singapore

4.7.1 Singapore's electricity industry was originally vertically integrated and Government-owned. Restructuring of the sector began in 1995, and in 1998 a day-ahead electricity market, the Singapore Electricity Pool, came into operation. 2003 saw the commencement of a fully competitive wholesale and retail electricity market, the National Electricity Market of Singapore (NEMS), and by the end of 2008 power generation assets had been divested by the state-owned holdings company. The NEMS is operated by Energy Market Company Pte Ltd (EMC), through which all of Singapore's electricity is bought and sold.

4.7.2 The Energy Market Authority (EMA) is the lead agency for the energy sector in Singapore. Formed in 2001, EMA is also the economic and technical regulator of Singapore's electricity and gas industries.

Generation

4.7.3 The NEMS is a competitive wholesale market. It is a half-hourly spot market for electricity, in which generators can submit bids for the dispatch of electricity, and are selected on a least-cost basis by EMC. Those which clear the market are paid the market price for electricity of their assigned node. Electricity purchasers pay the Uniform Singapore Energy Price (USEP) for energy, which is a weighted-average of the nodal prices at all off-take nodes.

4.7.4 There is mandatory regulation for the three largest generation companies to hold vesting contracts. These are bilateral contracts designed to curb market power, under which the price of electricity is pre-determined by EMA based on the long run marginal cost of a theoretical new entrant. At the start of the vesting regime in 2004, the vesting contract level was set at 65% of the total electricity demand. This was reduced as new generation companies entered the market and diminished the market power of these incumbents, and is currently at 40%.

4.7.5 In the NEMS, it is generally mandatory for all generators of 10 MW or more to be licensed. Generators of below 10MW at a single location are generally exempted from licensing as a generator and are licensed only as a wholesaler.

Transmission and Distribution

4.7.6 Transmission and distribution in Singapore are natural monopolies, of which SP PowerAssets Ltd (SP PowerAssets) is the licensed operator. SP PowerAssets currently owns, operates and maintains the transmission system in Singapore, which comprises of both the high and low voltage networks.

4.7.7 The transmission system is a natural monopoly, and SP PowerAssets is therefore subject to price regulation. Set by EMA, there is a price-cap economic regulation that designed to prevent the raising of prices and restriction of quality of goods and services offered.

Retail Supply

4.7.8 Until 2001, Singapore had a single electricity retailer or supplier (SP Services Ltd) that supplied all consumers. Following liberalisation, SP Services became the Market Support Services Licensee (MSSL), and continued to sell electricity to non-contestable customers at a regulated tariff, which are revised quarterly and are approved by EMA.

4.7.9 Contestable consumers are entitled to purchase electricity from the wholesale market, from a retailer of their choice or from the MSSL. There are currently nine licensed electricity retailers in Singapore, which obtain supply through the MSSL or, if registered as a market participant, may also purchase directly from the wholesale market.

4.7.10 Prior to April 2014, consumers with an average monthly electricity consumption of 10,000 kWh or more at a single location were eligible to become contestable. EMA lowered this contestability threshold from 10,000kWh to 8,000kWh on 1 April 2014, and it was further lowered to 4,000 kWh in late 2014. Non-contestable consumers are supplied by SP Services, which buys electricity on behalf of customers and pays the generators, transmission licensee and other market players based on the rates of the various cost components as approved by EMA. Non-contestable electricity tariffs are regulated by EMA, and revised on a quarterly basis to reflect the actual cost of electricity.

Regulation of the transmission sector

Price Setting Mechanism

4.7.11 EMA employs a price-cap regulatory regime to prevent the raising of prices and restriction of quality of goods and services offered. This regulatory approach works through the following principles:[47]

- EMA sets prices to reflect efficient level of costs;
- Flexibility for company to manage own costs;
- Financial reward for company if costs are reduced through efficiency savings;
- Incentive for company to pursue innovation and efficiency initiatives; and
- Consumers benefit from lower costs over the longer term.

4.7.12 Regulatory periods are five years long, to give medium-term certainty to the licensee. At the end of every five-year cycle, EMA reviews the parameters and resets the costs for the next cycle to reflect any efficiency gains. At the beginning of the most recent cycle, in 2011, transmission and distribution charges were reduced by 2.8%.

4.7.13 Overall electricity tariffs are regulated by EMA and revised quarterly to reflect the actual cost of electricity. Transmission and distribution network costs are reviewed annually, detailed below.

Tariff Calculation

4.7.14 The transmission tariff is set annually by EMA based on a CPI-X mechanism. Detailed in the Electricity License For Transmission Licensee[48], the calculation is summarised in Equation 16 below.

[47] EMA (23 Oct 2012): *Regulating Singapore's Electricity Industry*
[48] https://www.ema.gov.sg/media/files/licences/sp_powerassets/Licence/transmission_licence.pdf

Equation 16: Calculation of maximum average revenues in Singapore

$$M_t = \left[\alpha . P_t + (1-\alpha) . \frac{F_t}{Q_t}\right] \times A_t \times (1+S_t) + \frac{E_t}{Q_t} - K_t$$

Maximum average revenue per kWh

Average revenue per kWh

Return on fixed assets

Adjustment factor for transmission system losses

Performance adjustment factor

Exogenous costs for R&D and international obligations

Correction factor for losses/profits from previous year

Where: $P_t = \left[1 + \frac{CPI_t - X}{100}\right] \times P_{t-1}$

And: $F_t = \left[1 + \frac{CPI_t - X}{100}\right] \times F_{t-1}$

Deflated annually at CPI-X

And: α = weighting between average revenue per kWh and return on fixed assets

Source: IPA analysis

4.7.15 The transmission price is calculated along the following principles:

- At the beginning of each regulatory period, EMA, in consultation with the licensee, calculates the allowed revenues based on:
  - an allowed rate-of-return on existing fixed assets;
  - return of capital for investment;
  - projections of operation, maintenance and administration expenses;
  - forecast tax payments; and
  - sharing of capital and operating efficiency generated in the previous regulatory period to promote sustained productivity initiatives.
- The distribution tariff is calculated based on dividing these allowed revenues by the estimated quantity of delivered electricity.
- This tariff is revised on an annual basis using a CPI-X mechanism, detailed in Equation 16
- There is an additional correcting factor to compensate for greater or lower than expected revenues from the previous year. This is based on any differences of more than 2%.between the quantity of electricity received by consumers and the quantity of electricity sales forecasted by the licensee.

Quality Regulation

4.7.16 EMA sets Performance Standards, detailed below in Table 7, to prevent "cutting of corners".

Table 7: Transmission Performance Standards

Service dimension	Service indicator	Service standard	Performance target (%)
Availability of Supply	Minimum advance notice for planned interruption of electricity supply	7 calendar days	95
Reliability of Supply	Number of power failure incidents* caused by failure of, damage to, or operation of Licensee's equipment or cables	0	100
Restoration of Supply	Time taken to restore electricity supply for each power failure due to failure of, damage to, or operation of Licensee's equipment or cables rated at 22kV and below	3 hours 2 hours	100 90
Quality of Supply	Time taken to rectify voltage complaint or limit violation	2 calendar days	95
	Time taken to correct a voltage complaint that requires network reinforcement	6 months	99
	Number of voltage dip incidents* due to failure of, damage to, or operation of Licensee's equipment or cables	0	100
Providing Supply	Time taken to implement electrification scheme requiring new substations after take-over of substation (up to 22kV)	10 weeks	90
	Time taken to implement service connection requiring cable installation work, after premises to be supplied with electricity is ready to receive cable	6 weeks	90
Customer Contact	Time taken to reply to a written enquiry or complaint	7 working days	95
Metering Services	Time taken to attend to meter problem at site upon notification	8 calendar days	95

* Only incidents where the Licensee is determined by the Authority to be at fault will be counted.
Source: EMA (2014): *https://www.ema.gov.sg/page/90/id:133/*

Treatment of RAB

4.7.17 A return on the RAB, representing existing fixed assets and project new investments, is allowed under the transmission tariff. This must be calculated "on a reasonable basis based on commonly accepted economic and financial principles" [49].

4.7.18 A return of capital for new investments are calculated based in a straight-line-depreciation methodology, which is defined as "the amortisation of the cost of assets through equal annual charges over the estimate service life of an asset"[49]. The return on existing fixed assets is calculated net of straight-line-depreciation.

Fuel costs arrangements

4.7.19 Under the liberalised market structure of the NEMS, generation is fully competitive. Generators are responsible for the contracting of fuel from international suppliers, due to the lack of indigenous fuel resources. The cost of fuel is therefore reflected in the price of electricity, which is based on the average fuel oil price in the previous three months and is ultimately borne by end consumers.

[49] Condition 22, Clause 5 of the Electricity Licence For Transmission Licensee. Electricity Transmission Licence issued by EMA to SP PowerAssets Limited.

Key lessons

4.7.20 Singapore's market structure has been deemed to be widely successful:

- Competition in the generation sector has motivated generation companies to switch from oil-fired steam plants to more cost efficient gas-fired plants, leading to a reduction in costs;
- Over 75% of demand have retail choice in the supply sector; and
- In the distribution sector, regulation has brought about lower rates, while maintaining the high performance of the grid (less than 0.5 unplanned customer minutes lost per year).

4.7.21 These results have been attributed to an effective regulatory framework and the close partnership between EMA and industry. By gradually opening up the number of consumers to contestable supply, it has allowed competition to drive down tariffs and improve operational efficiency.

4.8. Case Study 8 – New South Wales, Australia

4.8.1 The electricity market in New South Wales, Australia (NSW) is one of six jurisdictions of the National Electricity Market (NEM), a compulsory wholesale pool into which generators sell their electricity. The main customers are retailers, who buy electricity for resale to business and household customers. The wholesale electricity market is liberalised and is regulated by the Australian Energy Regulator (AER).

Generation

4.8.2 Electricity in NSW is generated from a wide range of fuel sources, including coal, natural gas, hydro, wind, biomass and solar. NSW has an installed capacity of 19GW (including 9GW from renewable sources), and maximum demand of about 15GW. Reliability of supply for the last ten years has been 99.97% or higher. The NEM is made up of five regional markets including NSW. The transport of electricity from generators to consumers is facilitated through a 'pool', or spot market. All output is aggregated and scheduled at five minute intervals to meet demand.

Transmission

4.8.3 Transmission is operated by TransGrid, a state-owned enterprise, which is regulated by the AER. Transgrid is subject to rate-of-return regulation and an absolute revenue cap adjustment equal to CPI.[50]

Distribution

4.8.4 NSW has three state owned distribution companies, AusGrid, Endeavour Energy and Essential Energy. These were subject to a weighted average price cap (WAPC), which set a ceiling on a basket of distribution tariffs, and allowed individual tariffs to be adjusted, as long as the weighted average remained within the ceiling.[51] As of 1st July 2014 the AER switched distribution network supplier regulation to a revenue cap[52].

Retail Supply

4.8.5 The electricity supply market was regulated by The Independent Pricing and Regulatory Tribunal (IPART), but was deregulated as of 1 July 2014 in NSW. Prior to deregulation, the supply sector was subjected to a WAPC.

Regulation of the distribution sector

Price Setting Mechanism

4.8.6 The AER made the decision to switch regulation for distribution networks from a WAPC to a revenue cap in NSW commencing 1 July 2014 for all standard control services. The AER deemed that a WAPC has not, and is unlikely to provide an incentive for distributors to set efficient prices.

4.8.7 According to the AER a revenue cap will provide benefits in terms of efficient cost recovery and incentives for demand side management.

[50] Transgrid (2013): *Revenue Proposal 2014-15/2018-19*
[51] Australian Competition and Consumer Commission (2010): *State of the Energy Market 2010*
[52] Oakley Greenwood: *Network pricing under a revenue cap*

Equation 17: Revenue cap calculation for NSW

$$MAR_t = AR_t + I_t + T_t + B_t$$

$$AR_t = AR_{t-1}(1 + CPI_t)(1 - X_t)$$

Where:

MAR_t is the maximum allowable revenue in year t.

AR_t is the annual smoothed revenue requirement in the Post Tax Revenue Model for year t.

I_t is the sum of incentive scheme adjustments in year t.

T_t is the sum of transitional adjustments in year t. Likely to incorporate but not limited to adjustments from the transitional regulatory control period.

B_t is the sum of annual adjustment actors in year t. Likely to incorporate but not limited to adjustments from transitional regulatory control period.

CPI_t is the percentage increase in the consumer price index.

X_t is the X-factor in year t.

Source: AER (2013): *Stage 1 Framework and Approach Paper – Ausgrid, Endeavour Energy and Essential Energy*

Alternative Control Services

4.8.8 Individual price caps will remain in place for individual services offered by the distribution companies. These services include meter provision, maintenance and data services, public lighting services, and ancillary network services.

Quality Regulation

4.8.9 Additional incentive schemes have been applied by AER. Its function is to encourage distributors to encourage appropriate levels of service quality, maintain network reliability, incentivise efficient capital and operating expenditure, and to share efficiency gains/losses between distributors and consumers. Targets for quality of service have been put in place, and failure to meet targets may result in financial penalties.

4.8.10 **Service target performance incentive scheme (STPIS**) – The STPIS aims to safeguard service quality for customers against incentives for the distributors to seek out cost efficiencies.

The STPIS contains two mechanisms. The services standards factor (s-factor) adjustment to the annual revenue allowance for standard control services rewards (or penalises) distributors for improved (or diminished) service compared to predetermined targets. Targets relate to service parameters pertaining to reliability and quality of supply, and customer service. It also includes the guaranteed service level (GSL) component composed of direct payments to customers experiencing service below a predetermined level.

4.8.11 **Efficiency benefit sharing scheme (EBSS) –** The EBSS aims to provide continuous incentive for distributors to pursue efficiency improvements in operating expenditure (Opex), and provide for a fair sharing of these between distributors and network users. The financial incentives are based on the additional expected reward that the business would receive for an efficiency gain. Under the EBSS, the proportion of benefits of an efficiency gain retained by a distributor does not change based on the Opex target, so there is still a continuing incentive to make efficiency gains.

4.8.12 **Capital expenditure sharing scheme (CESS) –** the CESS provides financial rewards for distributors whose Capex becomes more efficient and financial penalties for those that become less efficient. Consumers benefit from improved efficiency through lower regulated prices. It approximates efficiency gains and losses by calculating the difference between forecast and actual Capex. It shares these gains or losses between distributors and network users.

4.8.13 **Demand management incentive scheme (DMIS) –** The DMIS is a mechanism to incentivise distributors to consider economically efficient alternatives to building more network.

To correct the failure of significant redundant capacity in a market where peak demand periods are brief and infrequent, the DMIS seeks to increase demand management through a demand management incentive allowance, (a capped allowance that can be incorporated into a distributor's revenue allowance for operating expenditure in that particular year) for distributors to investigate and conduct broad-based and/or peak demand management projects.[53]

Treatment of RAB

4.8.14 When a distributor's regulatory asset base (RAB) is updated from forecast Capex to actual Capex at the end of the regulatory period (five years), it is also adjusted for depreciation. The depreciation used to roll forward the RAV can be based on either actual Capex incurred during the regulatory period or the Capex allowance forecast at the start of the regulatory control period. The choice of depreciation approach is one part of the overall Capex incentive framework.

4.8.15 Dual function assets are parts of a distributor's network that operate in a way that supports the transportation of electricity over the higher voltage transmission network. Under AER regulation, distributors are allowed to address dual function assets in a distribution determination to avoid the need for separate transmission revenue proposals.

Fuel cost arrangements

4.8.16 No direct fuel cost arrangements are currently in place in New South Wales although there are indirect tax based subsidies that lower the cost of fossil fuels.[54] These, however, are being legislated against in an effort to increase focus on renewable energy.[55] Due to the liberalised nature of the generation sector, fuel costs are reflected in the wholesale electricity price to be taken up by consumers.

Key lessons

4.8.17 The rationale in shifting from a WAPC to a revenue cap was due to the AER's concerns that the WAPC was not, and is not likely to provide an incentive for distributors to set efficient prices. The theoretical benefits of a WAPC did not materialise in practice and AER chose a revenue cap for its individual tariff price stability, efficient cost recovery and incentives for demand side management.

4.8.18 Some of the main issues relating to WAPC were:

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[53] AER (2014): *Stage 2 Framework and Approach – NSW Distributors*
[54] Environment Victoria & Market Forces (2014): Pre-Budget Briefing Paper, *"Ending the fossil fuel industry's age of entitlement: An analysis of Australian Government tax measures that encourage fossil fuel use and more pollution"*
[55] Transforming NSW Energy Sector Bill 2014

- **Inefficient pricing –** The WAPC entails capping prices based on a weighted average of prices for individual tariffs within a basket of services. However, this presented an opportunity for distribution companies to maximise revenues through price discrimination. By offsetting higher tariffs for less price-sensitive or trapped customers (e.g. large industrial consumers) with lower tariffs for more price-sensitive consumers, distribution companies could effectively avoid setting efficient prices and maximise revenues whilst still operating within their weighted average price caps.
- **Volumetric risk –** Under WAPC, the distributor is subject to volumetric risk. The distributor would keep any additional profit when demand is higher than forecast and bear losses when the reverse occurred.
- **Regulatory burden** – Regulatory pressure on demand forecasts was high when using WAPC, as forecasts needed to be specific to individual tariffs within the basket of services.

4.8.19 Under a revenue cap, the following have been perceived:

- **Excess revenues are paid back to consumers –** Under a revenue cap the overall revenue that a regulated distributor can earn is capped, and any additional revenue earned is ‘paid back’ to the end-user.
- **Volumetric risk –** This is borne by consumers as distribution companies can change their tariffs to compensate for changes in demand, whilst still being within their revenue cap.

4.9. Case Study 9 – Great Britain

4.9.1 The regulatory framework in GB has recently undergone a significant change as Ofgem, the GB energy regulator, moves from RPI-X revenue cap regulation to a new incentive based model known as RIIO. Given the number of lessons learned from this transition that are applicable to the Hong Kong electricity market, this section takes a different form to the previous eight case studies. After overviewing the structure of the GB power market we discuss some of the issues with the previous RPI-X framework and explain how the new model is designed to meet the future needs of the GB power market.

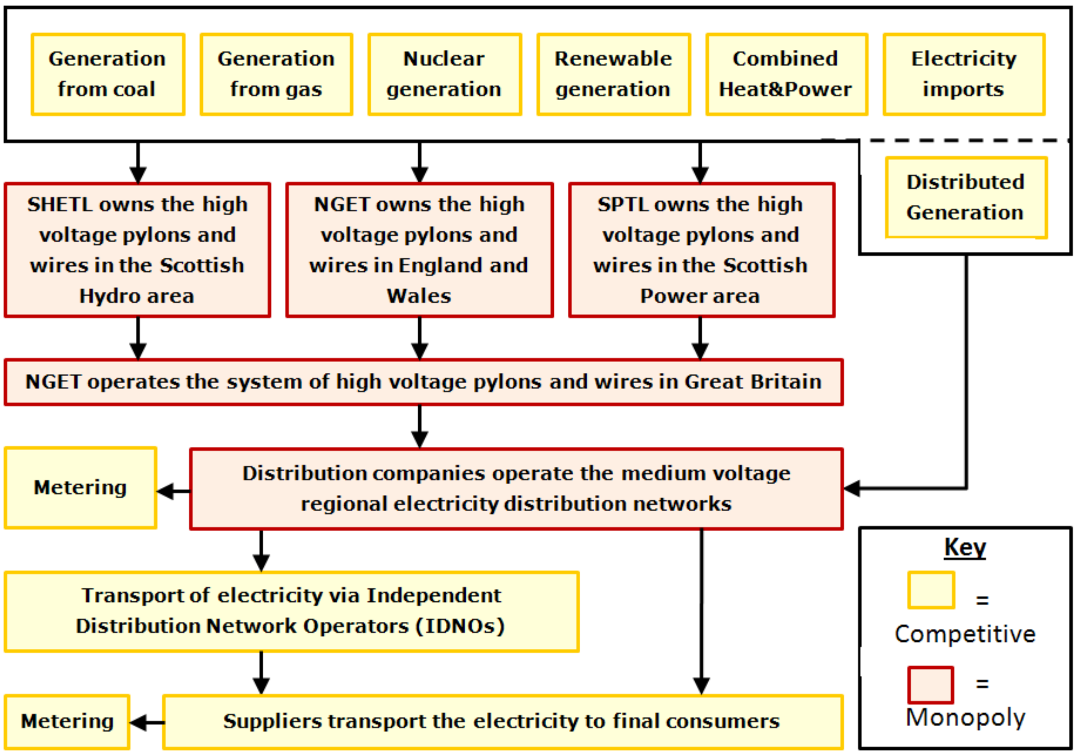
Market Overview

4.9.2 Since the start of privatisation in the 1990's, the electricity market in GB has evolved from a state controlled monopoly to a competitive market giving customers the freedom to choose their electricity supplier. In the process, a commodity market for wholesale electricity transactions has been established.

4.9.3 The Government, through the Department of Energy and Climate Change (DECC), provides the overarching policy direction and guidance for the industry, with a regulator, the Office of Gas and Electricity Markets (Ofgem), providing more direct regulation as necessary to protect the interests of consumers.

4.9.4 The industry structure in its present form can be grouped into four principal components: generation, transmission, distribution and supply. Generation and supply are open to competition and price is not regulated, whereas transmission and distribution, which are natural monopolies, are subject to price regulation. Figure 10 below provides a high level overview of the GB electricity industry.

Figure 10: High level overview of the structure of the GB electricity industry



Source: Ofgem

Generation

4.9.5 The generation sector is fully deregulated and open to competition. It is dominated by six large utility companies (Centrica, E.ON UK, EDF Energy, RWE npower, ScottishPower, and SSE), often referred to as the 'Big Six', who between them generated about 70% of the electricity consumed in GB in 2011, with the remainder produced by a number of smaller independents.

Transmission and distribution networks

4.9.6 National Grid Electricity Transmission (NGET), the transmission network operator in England, Wales and Scotland, has a central role in the industry. It is the owner of the transmission system in England and Wales and, along with the electricity transmission companies in Scotland, Scottish Hydro-Electric Transmission Limited (SHETL) and Scottish Power Transmission Limited (SPTL), has a statutory duty to develop and to maintain an efficient, coordinated and economic transmission system and to facilitate competition in supply and generation. Distribution remains a monopoly business and under the Utilities Act 2000 it has become a separately licensable activity. There are 14 licenced distribution network operators (DNOs), owned by six different groups, each responsible for a distribution service area. There are also four independent network operators who own and run smaller networks embedded in the DNO networks.

4.9.7 The companies have a range of different ownership structures but all have regional licensed monopoly rights over transmission and distribution assets and the provision of network services using these assets. The licence incorporates, amongst other things, the price control contract that specifies what network companies are expected to deliver and constraints on the revenue that can be earned from customers.

Retail Supply

4.9.8 The supply segment, or the retail sector for electricity, is also fully deregulated and open to competition. The retail companies, normally called suppliers, are responsible for purchasing electricity from generators, or from power exchanges, and selling it on to consumers. Suppliers compete for customers by offering tariffs in the open market. Again, the retail sector is dominated by the Big Six utilities, who together accounted for approximately 90% of the market in 2011.

RPI-X

Overview

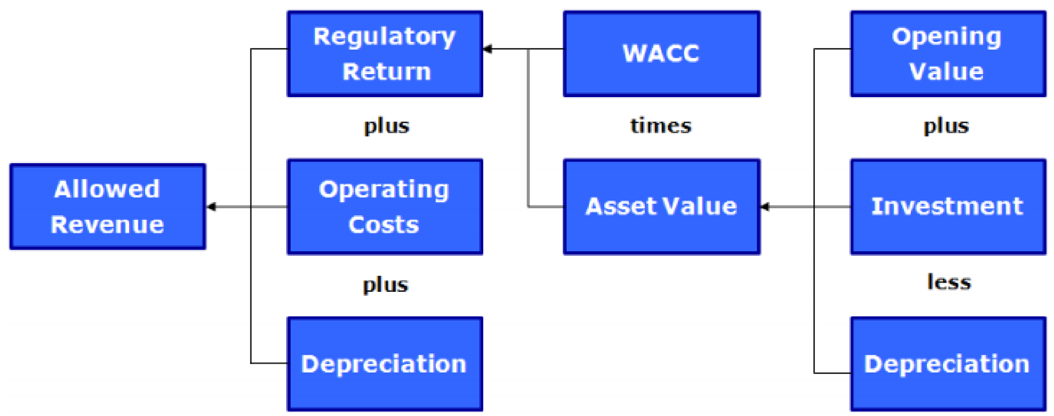
4.9.9 Since privatisation energy network companies have been subject to RPI-X regulation, an incentive-based regulatory regime discussed in Section 3. While the precise implementation differed across electricity and gas, and transmission and distribution, the basic structure was that the rate of change in average revenue was subject to an annual cap linked to the retail price index (RPI) and an additional X-factor. The X-factor primarily reflected expected efficiency improvements, capital investment requirements and rewards or penalties for service performance. The regulated transmission and distribution companies were able to retain financial benefits, if they outperformed the underlying assumptions of the allowed revenue calculation. Similarly, if they underperformed, they had to bear some of the associated cost.

Calculating the price control

4.9.10 Under RPI-X, as applied by Ofgem, an ex-ante price control is calculated by estimating the required efficient costs of operating the network, including any necessary extensions and improvements and the costs of financing this expenditure, over the price control period. The price control is set so that the net present value of allowed revenue equals the net present value of expected costs for the period. There is also an adjustment for under or over-performance in previous periods.

4.9.11 Base allowed costs are calculated as the sum of forecast controllable operating expenditure (Opex), forecast depreciation and the forecast return on the regulatory capital value. Total allowed costs are calculated by incorporating adjustments for specific incentive allowances and under or over-recoveries from the previous price control period. Forecast pass through-costs are added to this estimate of base allowed costs to determine the allowed price control revenue, but to the extent that these costs are different from that assumed in setting the price control, allowed revenue will flex to allow networks to recover the actual levels of such costs. Figure 11 shows the 'building block' approach used by Ofgem to calculate the allowed revenue under RPI-X.

Figure 11: Stylised building blocks of RPI-X regulation



Source: Ofgem

4.9.12 Ofgem provides the following descriptions of how each of the 'building blocks' is calculated.[56]

- **Forecast base operating expenditure (Opex):** in transmission, actual base controllable operating expenditure, from the most recent available annual data is adjusted to take account of exceptional items and expected increases in operating expenditure. Adjusted base operating expenditure is then rolled forward by an assumption about the expected efficiency improvement. In gas and electricity distribution, the starting base is a benchmarked view of costs, reflecting actual relative performance and a view on expected changes in overall productivity of the sector (frontier shift) and the extent of expected catch-up to the frontier (or to average performance or the upper quartile). The efficiency target can be based on a review of efficiency over time and/or benchmarking with other companies or other sectors. Bottom-up benchmarking, focusing on the potential efficiency of individual processes can also be used.
- **Other Opex:** a number of different operating expenditure items are then added to base operating expenditure. These include allowances for pension deficits, tax and industry-specific factors (e.g. for example 50% of replacement expenditure (a

[56] https://www.ofgem.gov.uk/ofgem-publications/51984/supporting-paper-history-energy-network-regulation-final.pdf

capital investment) is treated as operating expenditure in gas distribution, primarily for financing reasons).

- **Depreciation:** the depreciation charge is calculated by making an assumption on the expected average life of the assets and applying this to the Regulatory Asset Value (RAV), usually on a straight-line basis. In energy different asset life assumptions have been made across the industry as well as between pre- and post-vesting assets, and profiling arrangements have changed over time.

- **Capital investment (Capex):** forecast capital investment is determined by reviewing business plans presented by the networks and adjusting these for expected efficiencies or for possible changes in the scale or timing of investment plans. Increasingly, capital spend is linked to specific outputs.

- **Regulatory asset value (RAV):** the RAV is calculated by determining the opening value at the start of the period and rolling this forward by forecast net capital investment (capital investment net of depreciation). The opening value of the RAV is calculated by taking the opening value at the previous period and rolling this forward by actual capital expenditure and inflation. The precise details of when forecast expenditure is replaced with actual expenditure in the RAV will depend on whether the adjustment is made at the start of a price control period or a rolling adjustment is made.

- **Return (WACC)**: the return on the capital value is calculated by multiplying the RAV by the regulatory weighted average cost of capital (WACC).). When tax allowances are included in the calculation of allowed revenue directly, a real post-tax WACC is used.

- **Allowances for specific incentives:** the allowed revenue calculation also includes allowances for specific incentive schemes. In the case of energy networks, these include allowances to be earned from the Information Quality Incentive (IQI) scheme and the Innovation Funding Incentive (IFI) scheme.

- **Under- or over-recovery adjustment:** an adjustment may also be made to the calculation of allowed costs to reflect over or under-recovery of allowances in the previous control period.

- **Pass-through items:** the expected cost associated with pass-through items will be added to allowed costs to determine price control revenue. These are items pre-determined by Ofgem, whose costs are considered to be outside of the control of the regulated business (e.g. licence fees to fund Ofgem) and the costs are passed on directly to consumers. If the actual costs are different to forecast, an adjustment is made to the price control revenue during the period (for pass-through items) or at the next price review.

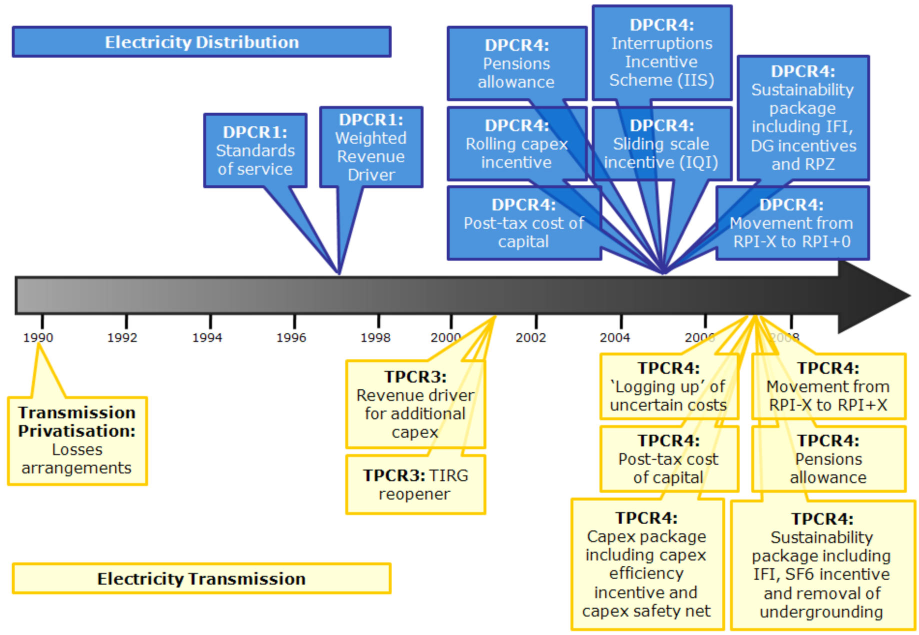
- **Financeability:** financial models are used to determine whether the regulated energy network is financeable under the proposed control. Financeability is assessed using a range of different financial ratios including the net debt/RAV ratio and the adjusted interest coverage ratio, each calculated for the notional regulated company. If Ofgem determines there are concerns surrounding financeability due to the effects of the proposed control on allowed revenue, ability to raise (debt and equity) finance and calculations by credit rating agencies, adjustments can be made to the control to ensure that the network can finance its functions.

Development of the RPI-X methodology

4.9.13 This framework developed and evolved since being introduced in the UK gas market in 1986 and then the electricity sectors in 1990, adapting to lessons learned and to the changing nature of network services. Originally, the focus was on providing incentives to improve cost efficiency, however over time additional objectives were introduced. The most significant changes were implemented as part of the recent price controls. Initiatives were put in place to further the sustainability agenda, facilitate Capex efficiencies, innovation and improved service quality, as well as to reflect changes in financial aspects of the controls (e.g. pensions and cost of capital). Measures were also introduced to reflect increased uncertainty about what networks needed to deliver during the five-year price control period (resulting in more revenue drivers, re-opener arrangements and ex-post mechanisms.

4.9.14 Figure 12 below highlights some of the key changes in the electricity price controls since 1990.

Figure 12: Key Changes in the electricity price controls



Note: in TPCR4, RPI+X was applied from 2007/08 at a level 2% above inflation. The main driver of this increase in allowed costs was the increased capital investment that was required over the period, specifically additional connections and associated reinforcement work to deliver required capacity.
Source: Ofgem (2009) *Regulating Energy Networks for the Future: RPI-X@20- History of Energy Network Regulation*

RPI-X@20

4.9.15 The RPI-X method is generally considered to have been a success in GB for reducing costs. According to Ofgem it delivered lower network prices (a 50% reduction in network costs since 1990), £35 billion of increased investment and significant improvements in network reliability since the companies were privatised twenty years ago.[57] However, in March 2008 Ofgem announced their RPI-X@20 review which sought to consider whether RPI-X based price regulation remained fit for purpose. There were two main reasons for the review:

- the changing nature of energy network services, reflecting the role the companies could play in the delivery of a sustainable energy sector; and
- the need to address concerns with the RPI-X framework.

[57] RIIO - a new way to regulate energy networks: Factsheet 93 (2010) *https://www.ofgem.gov.uk/ofgem-publications/64031/re-wiringbritainfs.pdf*

Changing nature of energy network services

4.9.16 Going forwards, the energy networks pose a potential obstacle to the delivery of a secure and sustainable energy sector. The scale, shape, location and flexibility of the networks could be one of the most important factors that affects whether new low carbon generation can be transported to customers in required timescales. Similarly, the design of the networks will influence whether and how changing patterns of energy demand are reflected in decisions relating to network enhancement, maintenance and operation. Their role in making the energy sector more sustainable in the future means that network companies will have to make new and different decisions over which there has been significant uncertainty about what needs to be done and when. This changes the nature of network decision-making which in turn has implications for incentive-based regulation.

4.9.17 The focus on sustainable energy services also changes the timescales that decision-makers need to consider. Companies have always dealt with long-term network assets but this is now coupled with an increasing focus on long-term service provision and a greater focus on future customers. Companies and Ofgem also increasingly need to make decisions relating to delivery of environmental policy objectives.

4.9.18 Following the RPI-X@20 review, the role of the networks in the delivery of a low carbon energy sector was arguably the main driver of the decision to significantly adapt the regulatory framework.

Concerns with RPI-X regulation

4.9.19 As their naturally monopolistic nature means that network industries will likely be subject to regulation indefinitely, the interactions between the regulator and the regulated companies represent a stylised example of mechanism design in a repeated principal-agent game with asymmetric information and uncertainty. A number of concerns have arisen with the RPI-X framework over time, some of which reflect the characteristics of the repeated principal-agent game and the design of incentive mechanisms. Some of the major issues that have been raised include:

- **Focus only on cost savings –** Whilst the incentive to encourage companies to deliver cost savings was successful, it had an unintended consequence of shifting the focus away from output delivery. Additional incentive mechanisms were needed, for example relating to quality of service. At times this resulted in RPI-X being complicated and burdensome and there were difficulties striking a balance between cost saving incentives and output delivery incentives.
- **Potential bias spending towards Capex –** Incentives to make cost savings have varied between capital and operating costs since higher Capex leads to a higher RAV, and therefore higher absolute return, while Opex spending is purely a pass through. This may have affected the choices that companies made, potentially with a bias in favour of capital investment solutions, leading to higher long-term cost.
- **Lack of focus on customers** – Until the latest Price Control Reviews (PCR), neither the regulator nor the companies collected consistent information on customers' needs, and therefore did not know whether the RPI-X framework was meeting them. Without being encouragement to focus on consumers, companies worked to please the regulator, having infrequent and limited interaction with their customers.
- **Lack of incentive to innovate** – Regulators focused on allocative and technical efficiency when setting five-year price controls, paying little attention to the more dynamic benefits of competitive processes. Combined with the predominantly risk

averse nature of most monopoly networks, this has been seen to lead to relatively low levels of innovation, with companies not seen to be open to new ideas.

- **Incentive to manipulate future price controls** – With five-year regulatory cycles, and increased data collection and monitoring, regulators have the opportunity to set future price controls at a level that is considered to be more reflective of actual costs. This is beneficial for allocative efficiency but can negatively influence technical efficiency as companies may adjust production choices, and the information they reveal, to influence future price controls.
- **Efficiency incentive reduces over price control period** – The strength of the cost saving incentive has also varied depending on when savings were made. Under the initial RPI-X framework, companies benefited less from efficiency improvements made later in the price control period as there was less time before prices were reset to transfer the savings to consumers. While Ofgem attempted to address the issue by redesigning the incentives to allow companies to benefit for a full five years from the time of an innovation, discussion about the impact of the timing of the price control review on company decision-making continued.
- **Regulatory burden** – The five-year cycles may have also resulted in relatively high regulatory burden, with only a brief interlude when one review is completed and implemented before the next starts. Moreover, the fact that the regulator developed and adapted the price control frameworks over time, adding on new mechanisms and requirements, led to complaints about increased regulatory burden and complexity of the regulatory regime.
- **Lack of long-term investment focus** – The process of reviewing price controls every five years has potentially encouraged companies to become overly focused on five-year regulatory cycles rather than the length of time consistent with asset and service delivery planning. The absence of any focus on the long-term in the regulatory framework has had implications for decisions relating to innovation, asset stewardship and trade-offs between long-term quality of service and cost savings.

RIIO

4.9.20 Following the conclusion of the RPI-X@20 review in October 2010, Ofgem published its decision to introduce a new regulatory framework. RIIO, the new regulatory model, is an incentive-based framework that sets a constraint on the revenues that network companies can raise from customers during the price control period. RIIO stands for:

Revenue = Incentives + Innovation + Outputs

4.9.21 The intention is that the revenue that companies can earn is linked to performance in playing a full role in the delivery of a sustainable energy sector and delivering long-term value for money network services. Those that deliver outputs, innovation and associated lower costs have the potential to earn above normal returns and those that don’t deliver earn below normal returns.

4.9.22 Starting from 2013, the RIIO model is being implemented for the first time in the current price control reviews for gas distribution, and electricity and gas transmission. It will then be implemented in the 2015 electricity distribution price control review.

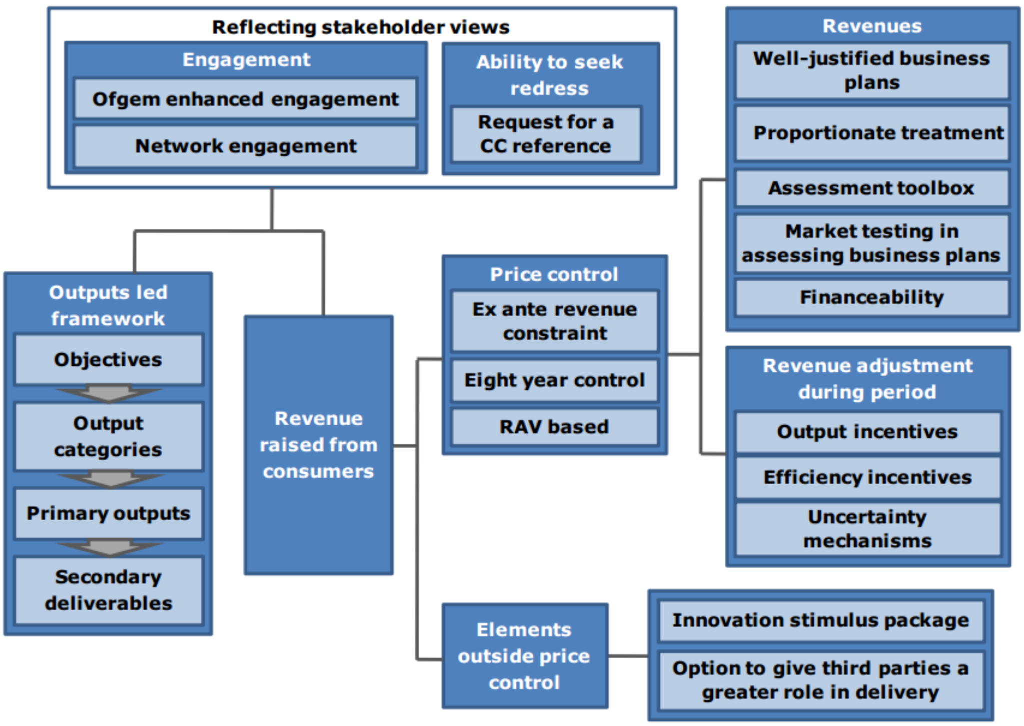
4.9.23 According to Ofgem, the three economic principles that influenced the design of RIIO were that it should:

- effectively mimic the benefits of dynamic competition;

- be clear and credible; and
- help to deliver environmental objectives.

4.9.24 While some features of the previous RPI-X regime survive, including retaining an upfront price control so companies know the revenue they are allowed to earn, adjustments for inflation and a return on the regulatory asset value, there are also significant changes. For example, under RPI-X the revenue constraint was presented as an allowed rate of change in average revenue, the X-factor. However, in practice observed changes in prices did not relate to the RPI-X formula and the determination of the control was far removed from the idea of specifying a single efficiency factor. With RIIO, Ofgem will specify base revenue for the price control period so there will be no explicit 'X factor'. Figure 13 below provides an overview of the main elements of the model.

Figure 13: Elements of the RIIO model



Note: CC refers to Competition Commission

Source: Jenkins, Cloda (2011) *RIIO Economics: Examining the economics underlying Ofgem's new regulatory framework*, Centre for Competition and Regulatory Policy Winter Workshop

4.9.25 We discuss below the main components, as well as how the RIIO design corresponds to the economic principles mentioned above and how it differs from the previous RPI-X framework.

Outputs

4.9.26 Outputs are core to the RIIO model, with the regulatory contract specifying what network companies are expected to deliver in return for revenue earned from customers.

4.9.27 Under RPI-X the extent to which outputs were specified in the regulatory contract has varied over time and across the network sectors. Despite twenty years of regulation, there has not been a comprehensive and consistent set of outputs in any sector. After privatisation, the focus was on providing a safe and reliable system, with company and regulatory decisions affected by engineering standards and Health and Safety Executive requirements. Customer service standards also evolved in distribution, arguably in a piecemeal fashion. In recent years the requirements on companies has expanded, with more focus on customer service, the environment and vulnerable consumers.

4.9.28 The RIIO model moves to a much greater emphasis on incentivising delivery of outputs relating to the customer experience and the environment, with the focus on six categories. These are:

- **Customer satisfaction –** Satisfaction of consumers, including a broad spectrum of network users, with network services.
- **Reliability and available –** Aspects of reliability and availability of network services that consumers are concerned with (e.g. number and duration of outages, constraint costs).
- **Conditions for connections –** The process for new / enhanced connections to the network.
- **Environmental impact –** Impact of network operation on the environment (including noise / visual impacts) and contributions to environmental targets.
- **Social obligations –** Services to fuel poor and vulnerable customers.
- **Safety –** Compliance with Health and Safety Executive safety standards.

4.9.29 Other measures, for example of asset health or of innovation developments, will not be directly incentivised but will be monitored by Ofgem on a regular basis and in some cases may be linked to base revenue. These secondary deliverables will inform company decisions about enhancement, stewardship and operation of the network, thereby protecting long-term delivery of sustainable network services. Ofgem expects companies to manage these aspects of network service provision efficiently and effectively and would be expected to take action if there is concern that a company is putting the long-term delivery of outputs and value for money at risk.

4.9.30 An understanding of customer needs played a limited role in setting standards under RPI-X, at least until the most recent price controls. Under RIIO the emphasis is on identifying outputs that relate to the aspects of network services that matter to existing and future customers and the broad contribution of that network companies in the development of a more sustainable energy sector. The regulator and the companies are working with a wide range of stakeholders to develop output measures that are material, controllable, measurable, comparable, applicable and legally compliant. While not all of the outputs that may be developed will meet all these criteria, the strength of financial incentives would be expected to reflect this, in time leading to outputs becoming relatively stable. Learning and adaptation is therefore likely to be an important element in the development of the RIIO framework, especially over the first price control period.

4.9.31 In some circumstances, outputs were developed with RPI-X to begin to incentivise companies to prioritise wider goals other than price reductions, such as quality of service. Here, they tended to be considered separately from the costs and revenue in the price control resulting in a disjointed relationship between delivery performance and the revenue and returns earned. With RIIO, the base revenue estimate, including investment requirements, will be based on an assessment of the efficient costs of delivering the agreed outputs and long-term value for money. The return earned will vary with output delivery performance.

Incentives

4.9.32 In light of the timing issues highlighted under RPI-X, RIIO has been designed to encourage companies to consider time horizons that are most relevant for efficient planning and delivery decision-making. A key change is the extension of the length of the price control from five years to eight years. This change is expected to help shift the focus of the companies onto the longer term. However, it will not remove all problems associated with having a known and identified fixed point at which price controls are reset. The RIIO model therefore also delinks the following aspects of the price control from the review cycle.

- As part of their business plans, network companies will be required to set out a long-term corporate strategy. They will be expected to assess alternative options for delivering outputs, setting out longer-term costs and benefits for each and will need to consider the value of keeping options open where there is uncertainty about how best to deliver.
- Outputs will be set for the long-term where possible. Where business plans are well-justified, Ofgem expects to include funding in the price control related to delivery of outputs and/or efficiency savings in future periods. Companies will also be encouraged to include in their plans innovation costs focused on delivery of long-term value for money network services.
- A proportion of total expenditure will continue to be financed through the regulatory asset value (RAV) which itself is a long-term instrument that spans a number of price control periods. Where possible Ofgem will give assurance on how long-term projects will be treated at future price control reviews. There is also commitment to not make retrospective RAV adjustments, save through the efficiency incentive rate, as long as outputs are delivered.
- Rewards and penalties associated with cost savings and output delivery will be triggered during the price control review rather than revenue adjustments being made at the next price control review. The length of the price control will not impact on the strength of the efficiency incentive in particular as this will be a pre-determined fixed proportion.
- Companies and third parties will be able to compete for partial funding for innovation projects through the Innovation Stimulus Package which will operate outside the price control framework with its own timetable.
- Where third parties are involved with some aspects of delivery, for example following an Ofgem-run tender process, the timescales involved will not necessarily be linked to the price control cycle. The decisions on whether to give a third party a greater role in delivery will also be informed by an assessment of the long-term costs and benefits.
- Ofgem has tried to make clear that it understands financeability principles, recognising the importance of transparency and predictability in this area particularly given the scale of the investment requirements in the energy network sector.

4.9.33 The combined effect of these changes and the longer price control period are intended to encourage companies to focus on time horizons that are consistent with efficient long-term decision-making.

Revenue constraint

4.9.34 The overall package is designed to ensure that efficient delivery of outputs is financeable, with the assumption that network companies will make decisions that are consistent with the objectives of playing a full role in the delivery of a sustainable energy sector and delivery of long-term value for money. The package will be calibrated so that companies that demonstrably deliver for consumers earn good returns, above the basic allowed return, whilst those that do not will earn below normal returns. There are three elements to the revenue constraint set out in the regulatory contract:

- **Base revenue:** Reflects the expected costs required to deliver efficient outputs;
- **Rewards & Penalties:** Revenue adjustments for rewards and penalties linked to performance in delivering outputs and long-term value for money; and
- **Uncertainty mechanisms:** Revenue adjustments for any uncertainty mechanisms included in the control.

Base revenue

4.9.35 As with RPI-X regulation, base revenue in the regulatory contract will be determined by estimating required efficient expenditure for the regulatory period. The 'building blocks' approach will continue to be used to estimate efficient expenditure, with an allowance for costs expensed each year ('fast' money), depreciation and an allowed return on the RAV.

4.9.36 RIIO differs from RPI-X, as implemented by Ofgem, in the way the elements of base revenue are determined. The base revenue in RIIO is calculated using a WACC, with notional gearing ratios for transmission and distribution services of 65% and 60% respectively[58], and a cost of debt based on a 10-year index[59]. The Price Control Financial Model, not used in RPI-X, derives incremental changes to base revenue during the RIIO price control period using a number of variables. These variables fall into four categories: the annual cost of corporate debt; total expenditure components; new or amended allowances on uncertainty mechanisms; and certain financial adjustments (such as pension variables, tax variables and legacy adjustments). RIIO implements an Annual Iteration Process, where these incremental changes are made. This process is conducted annually and reduces the need to log financial adjustments during the price control period to be made at the end of the period.

4.9.37 Company data will remain the primary source of information for setting the price control. To limit the risk of business plan costs being higher than needed there are also incentives in the framework to encourage companies to reveal their best available information on costs at the time of the price control review. The Information Quality Incentive (IQI), a mechanism introduced as part of the RPI-X framework in recent years, will be retained and extended to all four sectors. The jury may still be out on the effectiveness of this mechanism, most famous for its complexity, but retaining it is unlikely to have significant negative consequences. Other aspects of the model are intended to provide further information revelation incentives including changes in business plan requirements, benchmarking of forecast costs, the scope for differential treatment at the price control review, the risk of challenge from third parties resulting in a Competition Commission reference, and the threat of Ofgem giving third parties a greater role in delivery.

[58] Ofgem (2012): RIIO-GD1: Final Proposals - Finance and uncertainty supporting document, Ofgem (2012): RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas

[59] The 10-year index used is the iBoxx 10-year simple trailing average index

Rewards & penalties (revenue adjustments)

4.9.38 Ofgem is encouraging energy network companies to play a full role in delivery of a sustainable energy sector and to deliver long-term value for money network services. In the RIIO model there are a number of different incentives designed to collectively deliver these objectives, such as output delivery, cost-savings, innovation and environmental incentives. Where the rewards and penalties are financial they will result in an adjustment to revenue during the regulatory period. Where cost savings are made, the return earned can also be different to that allowed by the regulator. This means that the revenue earned can be higher or lower than base revenue. There are also reputational incentives, aimed to build the credibility of energy network companies that reduce their emission levels, which will not affect revenue during the period but may affect the proportionate assessment of business plans at future price control reviews.[60]

Uncertainty mechanisms (revenue adjustments)

4.9.39 Like other privately owned firms, network companies are responsible for managing normal business risk. They also get the benefit of favourable cost shocks. As with RPI-X, the RIIO price control includes uncertainty mechanisms where there is a risk of costs increasing or decreasing significantly due to factors outside the company's control. The impact of such uncertainty mechanisms on cash flow risk will also be taken into account in the allowed cost of capital. The aim is to limit the use of uncertainty mechanisms as far as possible, to avoid the risk of undermining efficiency incentives and potentially complicating the price control. Such mechanisms will only be used where they are expected to deliver value for money for existing and future customers and where they protect the network company's ability to finance efficient delivery. Where mechanisms are included they will, depending on their design, result in revenue adjustments during the period or at the next price control review should the identified events arise.

Fuel costs arrangements

4.9.40 Due to the liberalised nature of the generation sector, fuel costs are reflected in the wholesale electricity price to be taken up by the consumers.

Key lessons

4.9.41 From the point of view of the Hong Kong Environment Bureau, the GB experience with RPI-X over the past 20 years, and its move to the new framework, provides some interesting insights into this type of revenue cap regulation. While Ofgem generally consider RPI-X to have been right for its time, they moved to replace it because of concerns with the framework that had become apparent over the previous price control reviews, as well as the perceived change in the role of the energy network services in the delivery of a secure and low carbon energy sector in the future.

4.9.42 Whilst the incentive to encourage companies to deliver cost savings from the fundamental revenue cap based design worked well, it had an unintended consequence of shifting the focus away from output delivery. Additional incentive mechanisms were needed, for example relating to quality of service. This resulted in RPI-X being complicated and burdensome and there were difficulties striking a balance between cost saving incentives and output delivery incentives.

[60] http://www.city.ac.uk/__data/assets/pdf_file/0011/80939/Jenkins_RIIO-Economics_draft-paper-FINAL.pdf

4.9.43 Like in GB, the regulatory framework in Hong Kong has had a number of incentive mechanisms added to try to encourage the regulated utilities to behave consistently with the values of the public. Current tariff adjustments under the SCAs are included for: customer performance (supply reliability, operational efficiency, customer services), energy efficiency (energy saving, energy audit) and renewable energy & emissions performance.

4.9.44 Where outputs were developed with RPI-X they tended to be considered separately from the costs and revenue in the price control resulting in a disjointed relationship between delivery performance and the revenue and returns earned. With RIIO, the base revenue estimate, including investment requirements, will be based on an assessment of the efficient costs of delivering the agreed outputs and long-term value for money. The return earned will vary with output delivery performance.

4.9.45 Ultimately, the incentives under RPI-X to innovate did not prove strong enough to move the network companies to embrace the fundamental changes in the needs of the energy sector, even when companies were allowed to keep the gains from innovation for five years instead of just until the end of that price control. It is possible that this problem could be greater in Hong Kong, even if the regulation was price cap based instead of rate-of-return, given that utilities are vertically integrated while in GB the supply chain is fully unbundled. The supply chain comprises a series of activities which have very different economic drivers. This means that it may be difficult to implement some of the aspects of RIIO that are very targeted at letting the energy network services play a major role in delivering a secure and low carbon energy sector in the future.

5. PRICE SETTING MECHANISMS USED BY LOCAL HK UTILITIES

5.0 In this section we examine the price setting mechanisms used by the MTR Corporation Limited and franchised buses in Hong Kong. We examine their fare adjustment rate, quality regulation and key lessons.

5.1. Fare Adjustment Mechanism of the MTR Corporation Limited

5.1.1 The Fare Adjustment Mechanism (FAM), of the MTR Corporation Limited (MTRCL), shown in Equation 18, was adopted following a merger of the government-wholly-owned Kowloon-Canton Railway Corporation and the government-majority-owned (some 77%) publicly listed MTRCL in December 2007 to replace the fare autonomy of the pre-merger MTRCL. It was installed with the aim of addressing demand from the community that fares should be able to come down, not just go up, in accordance with the prevailing economic environment. This demand was derived from continued deflationary pressures in the early 2000s but no fare reduction. During the first two years after the merger (2008 and 2009), in accordance with the terms of the rail merger, fares were frozen and MTRCL offered fare reductions upon the merger. For the three subsequent years (i.e. 2010, 2011 and 2012), the FAM formula outcome resulted in upward fare adjustments in an inflationary period. MTRCL made considerable profits during this period and this raised concerns in the public domain.

5.1.2 The perceived inadequacy of the FAM to address MTRCL's profitability since the 2007 merger, and also its service performance and fare affordability provided the backdrop to the five-yearly review of the FAM formula jointly conducted by the Government and the MTRCL in 2012. The review of the FAM was completed in April 2013 and the revised FAM introduced an alteration of the methodology used to calculate the productivity factor.

Fare Adjustment Rate

5.1.3 The calculation of the fare adjustment mechanism is based on the Hong Kong Composite Consumer Price Index and the Nominal Wage Index (Transportation Section) in equal measure. The fare adjustment rate is then subject to a reduction by the new productivity factor.

Equation 18: MTRCL Fare Adjustment Rate

$$Fare\ Adjustment\ Rate = 0.5 \times \Delta CCPI + 0.5 \times \Delta WI - PF$$

Where:

$$CCPI = Composite\ Consumer\ Price\ Index$$

$$WI = Nominal\ Wage\ Index\ (Transportation\ Section)$$

$$PF = Productivity\ Factor$$

Source: *Legislative Council Brief on Review of the Fare Adjustment Mechanism of the MTR Corporation Limited (File Ref: THB(T)CR33/1017/99)*

Composite Consumer Price Index

5.1.4 The consumer price index measures the changes over time in the price level of consumer goods and services generally purchased by households. The composite consumer price index is the aggregation of three different series of CPIs in low, medium and high expenditure ranges.

Nominal Wage Index of the Transportation Section

5.1.5 The transportation section nominal wage index measures the changes in wage rates of transport employees - up to but not including supervisory level – by holding constant the structure of the transport sector labour force with respect to occupation and gender between two successive rounds of a Labour Earning survey.

Productivity Factor

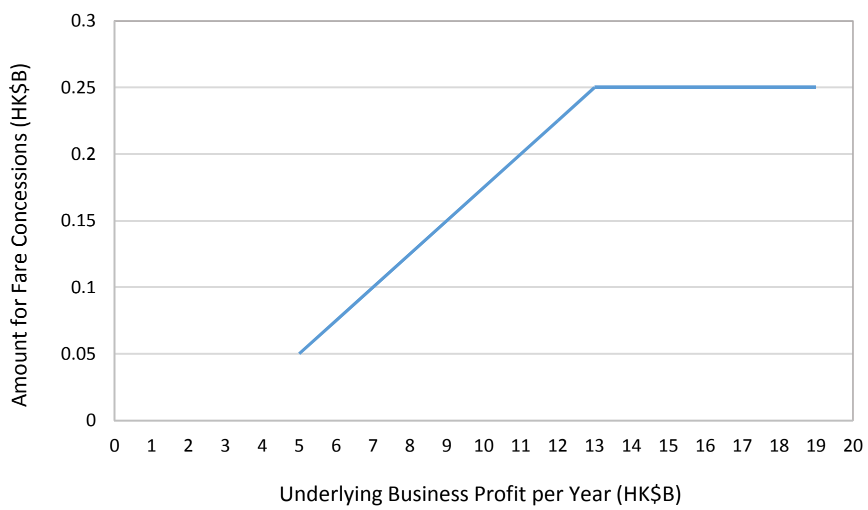
5.1.6 Following the review by the Government and the MTRCL in 2013, the productivity factor (PF) which was fixed at 0% from 2007 to 2012, a new objective methodology was introduced to compute the PF value for the FAM from 2013 to 2017. The new methodology involves measuring historical productivity based on MTRCL's output and input. Output is defined as revenue, and input is defined as operating expenses (before depreciation, amortisation and variable annual payment expenses) earned/incurred in the MTRCL's Hong Kong transport operations, as set out in MTRCL's audited financial statements. This output/input ratio is deemed to be the measure of productivity gain of the MTRCL's transport operation. Based on a compound annual growth rate (CAGR), the output/input ratio was 1.19% per annum for 2008 to 2012. A productivity factor has been set at half of this – 0.6% – for each of the next five years between 2013 and 2017.

Discounts and Caps

Profit-Sharing by MTRCL

5.1.7 A separate mechanism was introduced under the review of FAM to address public concerns about profitability of the MTRCL. The profit-sharing mechanism is designed to share MTRCL's profits with passengers in the form of the "10% Same Day Second Trip Discount" promotion. The underlying business profit extends to all profits earned in Hong Kong transport operations; Hong Kong station commercial business; Hong Kong property rental and management businesses; Hong Kong property developments; Mainland China and international businesses; and other businesses (principally Ngong Ping 360, railway consultancy and project management). MTRCL sets aside a pre-determined amount of underlying business profit of the preceding year to pay for the "10% Same Day Second Trip Discount" promotion. The amount of concessions given corresponding to profit is shown below in Figure 14.

Figure 14: Profit Sharing by MTRCL

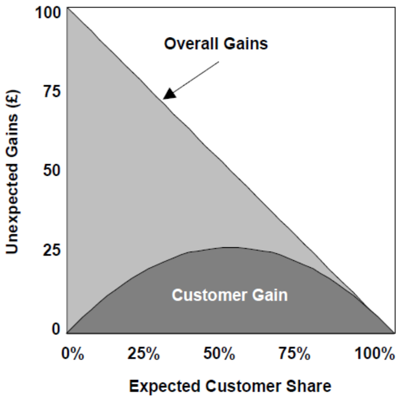


Source: *Legislative Council Brief on Review of the Fare Adjustment Mechanism of the MTR Corporation Limited (File Ref: THB(T)CR33/1017/99)*

Profit Sharing in Singapore's District Cooling Network

A profit-sharing mechanism exists in Singapore for district cooling services whereby 50% of profits are shared with the customer. The Electricity Market Authority of Singapore deem this to be the optimal level of profit-sharing under the assumption that the incentive to increase profits by lowering costs for district cooling services falls beyond this point, reducing overall profits, and therefore customer gain. This is illustrated in the diagram to the right.

Source: *EMA Price Regulation for District Cooling Services*



5.1.8 The above example of Profit Sharing in Singapore's District Cooling Network highlights the level of profit sharing in which customer gain is maximised (50%). Current profit sharing in MTRCL does not operate at the level in which customer gain is maximised. Profit above a certain return in the franchise bus network however, is shared with customers at this 50% level.

Affordability Cap

5.1.9 The review of FAM also introduced an affordability cap. The affordability cap is a direct answer to concerns over public affordability. Fare increase according to the revised FAM formula outcome will always be capped by the change in Median Monthly Household Income (MMHI) for the corresponding period. MMHI represents the average monthly domestic household income.

5.1.10 When the FAM results in fare increases greater than the change in MMHI, discounts will be applied to Octopus fares[61] such that the total realised change in overall fares is equal to the change in MMHI. If a change in MMHI is negative, the MMHI change will be deemed as 0%.

5.1.11 The affordability discount applied to the Octopus fares will be introduced in Year 1 to reduce the rate of fare increase to the change in MMHI; in Year 2 the discount will be halved, and removed entirely in Year 3. The affordability discount remains in place for Years 1 and 2 if a withdrawal would result in an effective fare increase above change in MMHI for the respective years. The discount will also remain in place if there is a reduction or no change in the FAM in the year following the installation of the affordability discount.

Quality Regulation

5.1.12 Quality of service is vital to the Hong Kong public, and as such, financial penalties have been put in place under the review of FAM to penalise train service disruptions that last a period of thirty-one minutes or longer. Financial penalties range between HK$1M and HK$15M depending on the length of the total service disruption. MTRCL is exempted from penalties if the event is outside of MTRCL's control e.g. bad weather or passenger behaviour. The financial penalties collected will be spent for the provision of fare concessions through the "10% Same Day Second Trip Discount" promotion.

[61] The fares charged to Octopus card holders

Key lessons

5.1.13 Overall FAM of MTRCL has the following key features:

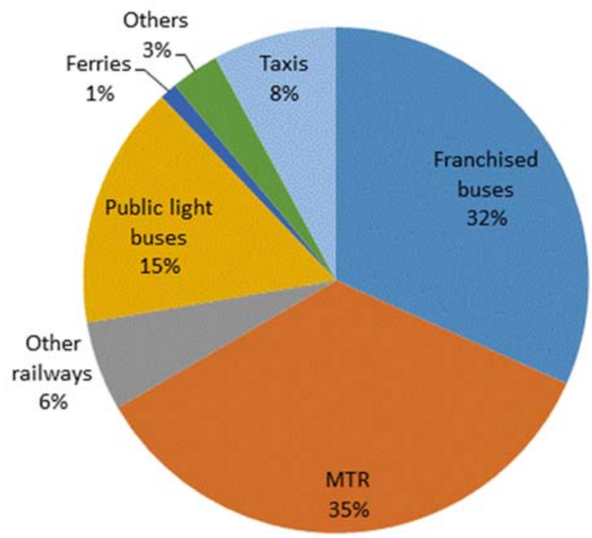
- Ensuring that fare adjustments are objectively calculated based on MTR's inputs and outputs;
- Providing an effective mechanism by which clearly defined and measurable data are, through pre-defined formula, able to be translated to fare adjustments;
- Providing incentives (through a penalty system) for MTRCL to improve their service reliability; and
- Including additional mechanisms to address profitability of the MTRCL and public affordability in the form of a profit-sharing mechanism and an affordability cap.

5.1.14 The concept of an affordability cap or profit sharing may help improve public perception and address public affordability.

5.2. Fare Adjustment Arrangement of Hong Kong Franchised Buses

5.2.1 Within Hong Kong, franchised buses make up 32% of the public transport system. The service is provided under six franchises granted to five private operators[62], specifically: Kowloon Motor Bus Company (1933) Limited (KMB), Long Win Bus Company Limited (LW), Citybus Limited (CTB), New World First Bus Services Limited (NWFB) and the New Lantao Bus Company (1973) Limited (NLB). According to the Public Bus Services Ordinance, a franchise may be granted by the Chief Executive in Council (CE-in-Council) following a public tender or in such other manner that CE-in-Council thinks fit. A franchise may last for a period not exceeding 10 years.

Figure 15: Hong Kong Transport Market



"Other railways" include Airport Express Line, Light Rail and tramway.

Source: Hong Kong Annual Digest of Statistics 2013

[62] Citybus Limited operates two franchises.

5.2.2 In assessing bus fare adjustment applications for the purpose of making recommendations to the CE-in-Council, the Government is guided by the Fare Adjustment Arrangement for Franchised Buses (FAA). The FAA comprises a basket of factors as set out below:

- Changes in operating costs and revenues since the last fare adjustment;
- Forecasted future costs, revenues and returns;
- The need to provide the operator with a reasonable rate-of-return. The Government would make reference to the WACC of the bus industry in considering the reasonable rate of return;
- Public acceptability and affordability. The Government would make reference to changes in Median Monthly Household Income and Composite Consumer Price Index;
- Quality and quantity of service provided; and
- A formula for a supportable fare adjustment rate.

5.2.3 The formula for a supportable fare adjustment rate was added to the FAA in 2006. The fare level will not be adjusted automatically according to the formula outcome. Instead, the formula outcome is for reference, which is monitored under the FAA by the Government on a quarterly basis. If it reaches -2%[63], the Government will proactively initiate a fare review and consider initiating a downward fare adjustment, taking into account the outcome of the formula and other factors in the FAA. This is to ensure cost reductions are passed through to consumers.

Equation 19: Hong Kong Fare Adjustment Formula

$$Supportable\ fare\ adjustment$$
$$= 0.5 \times \Delta WI + 0.5 \times \Delta CCPI - 0.5 \times Productivity\ Gain$$

Where:

$$CCPI = Composite\ Consumer\ Price\ Index$$

$$WI = Nominal\ Wage\ Index\ (Transportation\ Section)$$

Source: Legislative Council, LC Paper No. CB(1)249/12-13(06)

5.2.4 Fare increases are only considered on application by a franchisee. Once a fare increase application is received, the Government would obtain the necessary data from bus operators and through other sources, and assess the application according to the FAA. The LegCo Panel on Transport and the Transport Advisory Committee (TAC) would be consulted before a final recommendation is made to the CE-in-Council.

Fare Adjustment Rate

5.2.5 The outcome of the formula for a supportable fare adjustment rate provides an indicator as to whether the fare adjustment rate is supportable and justifiable at any given juncture. This helps to improve objectivity of the fare adjustment process. Yet, as mentioned above, the fare level is not adjusted automatically according to the formula outcome. The formula comprises a cost component and a productivity component. The cost component is made up of two indices, one relating to staff cost in the bus industry (in terms of the Nominal Wage Index for the transportation section) and the other to other operating costs

[63] Equivalent to about a 10 cent difference in average ticket price per bus journey.

(as reflected by the Composite Consumer Price Index (CCPI)), with a weighting of 50:50. The Productivity Gain represents the corresponding gains in efficiency, of which half is shared with consumers (resulting in the weighting factor of 0.5).

5.2.6 When the FAA was last reviewed in 2008/09, a productivity loss (-1.05%) was observed in the industry because of a drastic upsurge of fuel costs at the time and increasingly keen competition from other transport modes. Yet, in the interest of passengers, the passengers' share of productivity gain was set at zero, instead of taking the negative productivity gain value, until the next review. Another round of review on the FAA is now underway.

Discounts and Caps

5.2.7 Forecasts of future costs, revenues and return in addition to reasonable rate-of-return for the operator are factors under the FAA. When the FAA was last reviewed in 2008/09, a rate of return of ANFA of 9.7% was considered to be reasonable. Those franchisees observed to exceed the reasonable rate-of-return have to share profits exceeding 9.7% with passengers according to a 50:50 split. The passenger share is maintained by the bus company through a "passenger reward balance", a fund use to offset fare increases and provide fare concessions.

Quality Regulation

5.2.8 Quality and quantity of service is assessed as a part of the FAA through review of passenger satisfaction surveys, site surveys, complaint figures, accident rates and other factors.

Key Lessons

5.2.9 Overall the Fare Adjustment Arrangement has the following key features:

- Ensuring that fare adjustments are conducted based on a set of objective and transparent factors; and
- Managing the affordability of bus fares, while ensuring the commercial viability of the sectors participants.

5.2.10 It should, however, be noted that there is no separate and distinct fuel cost component in the FAA or in the formula for a supportable fare adjustment rate. Rather, fuel cost is taken into account in changes in operating cost, forecast of future costs, and as part of the cost component under the formula for a supportable fare adjustment rate.

5.3. Possible Applications to the Hong Kong Electricity Sector

5.3.1 Current price setting mechanism for the MTRCL is based on limiting increases in fares based on inflation indices (in addition to productivity factor and Median Monthly Household Income Index quarterly), as opposed to examining underlying costs. Adoption of such a mechanism as a whole in the electricity sector in Hong Kong would not be appropriate because the majority of costs are not related to inflation, with greater market exposure to fuel costs and the need for infrastructure investments to meet new environmental policy goals. There are, however, elements of the regulatory mechanism which could be applied to the Hong Kong electricity market, namely the concepts of a profit sharing mechanisms and an affordability cap. Both may aid tariff affordability, help smooth any increases and improve public perceptions of the electricity sector within Hong Kong.

Profit Sharing

5.3.2 The profit sharing mechanism within the regulated franchise bus system occurs on a 50:50 basis for profits above the rate-of-return of ANFA of 9.7%. Within the MTR, profit sharing occurs above certain absolute values, and shares roughly 1.5% of total underlying business profits of MTRCL (based on the 2012 audited account).

5.3.3 Under the current SCA for electricity sector in Hong Kong, all profits above the permitted level of return are transferred to the Tariff Stabilisation Fund, which ultimately belongs to customers. As such, this concept of profit sharing is already featured in the current regulatory framework and it should continue to be considered in suitable aspects for the development of future price setting mechanism. It could be an effective and popular policy to ensure tariff increases by the power companies are not excessive, and improve public perceptions of the electricity sector.

Inflation indices

5.3.4 There are a number of inflation indices which are used as a basis for tariff / bus fare increases. These include:

- **Composite Consumer Price Index (CCPI)** – the aggregation of three different series of CPIs in low, medium and high expenditure ranges; and
- **Median Monthly Household Income (MMHI)** – average monthly domestic household income; and
- **Industry Wage Index** – wage rates of sector employees up to but not including supervisory level, calculated by holding constant the structure of the sector labour force with respect to occupation and gender between two successive rounds of a Labour Earning survey. Under the FAM and FAA in Hong Kong, the Nominal Wage Index for the Transportation Section is used.

5.3.5 It would be difficult, however, to identify an appropriate index for adoption in the electricity sector. One option would be to base the index on the industry wage index (calculated in a similar way to how the Nominal Wage Index (Transportation Section) is calculated and used as a basis for MTRCL and franchised buses fares in Hong Kong). However, this would appear to be not very meaningful for electricity sector in Hong Kong as there are only two power companies, which raises the possibility of gaming. It would also not be appropriate to simply use CPI or RPI, given that the majority of costs (e.g. fuel cost, material and services, government rent and rates) are not directly related to these inflation indices.

Affordability Cap

5.3.6 The affordability cap under the FAM of MTRCL limits fare increases by any increase in the MMHI.

5.3.7 Applying a cap to the Net Tariff would be infeasible, as it might adversely constrain tariffs by not taking into account changes in fuel prices which constitute the bulk of the Net Tariff as these price changes are not linked to indices such as MMHI. Furthermore, given that emissions regulation are shifting the generation mix to cleaner but costlier natural gas-fired generation, the cost of generation is expected to grow beyond merely fuel price inflation.

6. HONG KONG POWER MARKET OVERVIEW

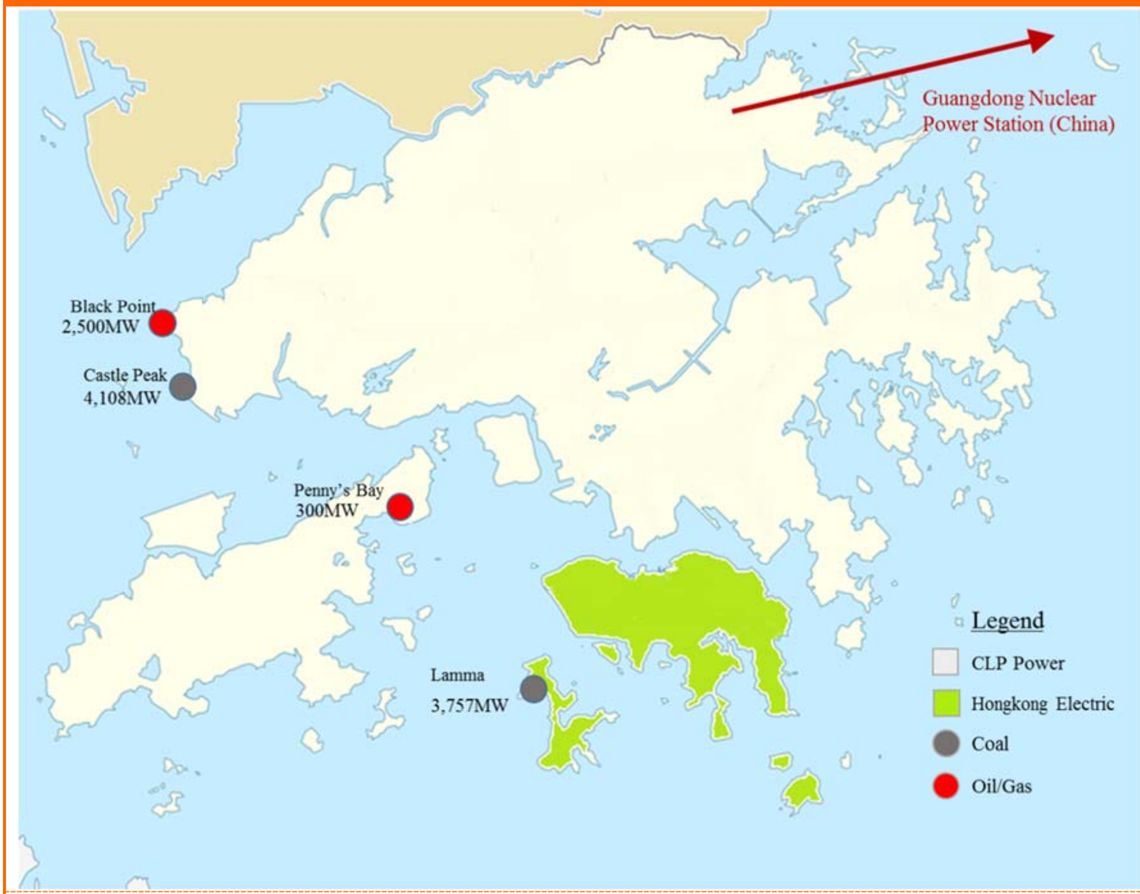
6.1. Overview of the Electricity Companies

6.1.1 The electricity supply in Hong Kong is currently provided by two privately-owned power companies, CLP Power Hong Kong Limited and Castle Peak Power Company Limited, (collectively: CLP) and The Hongkong Electric Company, Limited (HEC). Both power companies are vertically integrated utilities that own and operate their respective generation, transmission and distribution assets for supplying electricity to consumers in geographically separated service areas:

- CLP supplies electricity to Kowloon and the New Territories, including Lantau, Cheung Chau and most of the outlying islands; and
- HEC supplies electricity to Hong Kong Island, Ap Lei Chau and Lamma Island.[64]

6.1.2 These geographic areas, split by power company and also detailing their power stations, are illustrated in Figure 16 below.

Figure 16: Geographic Areas and Power Stations by Power Company in Hong Kong



Source: *http://commons.wikimedia.org/wiki/File:Map_of_Hong_Kong_18Districts_ZH.svg, IPA research.*

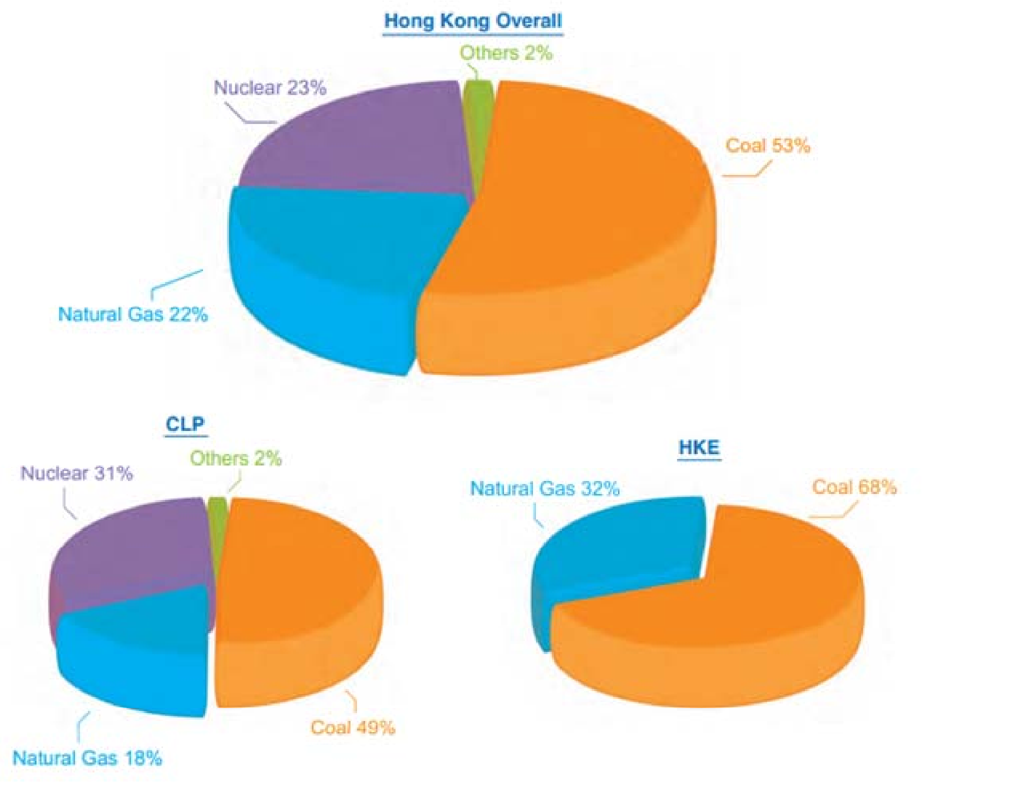
[64] Government of Hong Kong

6.1.3 CLP supplies electricity to 80% of the Hong Kong population.[65] It holds 70% ownership of three power stations it operates in Hong Kong – Black Point – a Combined Cycle Gas Turbine (CCGT) power station with 2,500MW capacity, Castle Peak – a coal-fired power station with 4,108MW capacity, and Penny's Bay – an Open Cycle Gas Turbine (OCGT) power station with 300MW capacity. CLP Power also holds 25% of a joint venture with Guangdong Nuclear Power in the Daya Bay nuclear power station in mainland China, with the option to purchase the normal offtake up to 70% of its 1,968MW capacity till 2034.[66]

6.1.4 CLP's total installed capacity in Hong Kong is 6,908MW, with access to a further 50% of 1,200MW capacity from the Guangzhou pumped storage power station, also in Mainland China.[67] In 2014, CLP recorded a new high maximum demand of 7,030MW.[68]

6.1.5 HEC owns and operates Lamma Power Station – including eight coal-fired units, five gas turbine units, two CCGTs, one wind turbine, and a solar power system with a total capacity of 3,757MW to meet the entire demand of Hong Kong Island, Ap Lei Chau and Lamma Island. The maximum demand of HEC is rather stable with the highest maximum demand record of 2,597MW in 2006.

Figure 17: Fuel Mix of Hong Kong in 2012



Source: Environment Bureau (2014): *Future Fuel Mix for Electricity Generation Consultation Document*

[65] The Climate Group
[66] World Nuclear News
[67] Government of Hong Kong
[68] ENB

6.1.6 A 720MVA interconnector has been installed between the two companies' transmission systems via a cross-harbour link. However, this is mainly for the provision of emergency support to one another reducing potential loss of supply to customers, and also for economy power exchange and sharing of reserve.

6.1.7 Hong Kong's peak energy demand is expected to grow at about 1% annually. With capacity retirements of coal fired generating units, which were commissioned in the 1980s and 1990s, beginning in 2017 and no new planned capacity currently under construction, future capacity shortfall is forecast to grow.

6.2. Consultation on Future Fuel Mix for Electricity Generation

6.2.1 In 2012, 53% of Hong Kong's overall electricity mix was powered by coal. However, with emissions reduction targets to be achieved by 2020 and future capacity shortfalls to be addressed, the Environment Bureau has put forward a public consultation to seek views on how best to approach the upcoming challenges within the Hong Kong power market. The consultation lists two options that seek to replace the capacity of retiring coal fired power stations with a lower carbon intensive supply, and to expand supply to meet future demand at a sustainable level.

- **Importing more electricity through purchase from the Mainland power grid**

  Under this option, a suggested fuel mix ratio of 50% of electricity demand met by import from mainland China (an increase of 30% on top of the current 20% imported by CLP from Daya Bay nuclear power station, Guangdong), 40% natural gas for local generation and the final 10% a mixture of coal and renewable energy. New cross-boundary transmission infrastructure will be required for delivering the extra 30% of electricity to the Hong Kong power grids. The Environment Bureau suggested that the import option would require an increase in interconnectivity between the Mainland and the two local power grids. This would also allow the introduction of competition within generation.

- **Increase local generation through increased usage of gas**

  Under this option, the total share of electricity coming from natural gas would increase from about 22% to 60%, coal and renewable energy would be at about 20%, while continuing to import nuclear electricity from Daya Bay Nuclear Power Station which would account for the remaining 20% of the overall fuel mix. According to the Environment Bureau, carbon intensity would be reduced by about 50% and the lower bound of 2020 air pollution emission reduction target would be met, but any further improvements to environmental performance brought by new generation units would be fairly limited. However, this would further expose the Hong Kong power market to international gas price volatility.

6.3. Overview of Regulation

6.3.1 Historically, electricity utilities in Hong Kong have been subject to rate-of-return regulation. The objective of this is to ensure customers receive adequate and reliable services at reasonable prices, and at the same time to provide the company with a 'fair' or 'reasonable' rate-of-return.

6.3.2 The electricity sector has always been privately-owned and operated in Hong Kong. The Government of the Hong Kong Special Administrative Region (the Government) currently regulates the sector through the Scheme of Control Agreements (SCAs), which are detailed in Section 6.4. In summary, these SCAs allow the two incumbent utilities to recover all operating costs and make a maximum return of 9.99% on their average non-renewable net fixed assets (the permitted rate-of-return for average renewables fixed assets is 11%). Prior to 2008, in the previous SCA, the permitted rate-of-return was 13.5% on average net fixed assets financed by borrowings and an extra 1.5% on those by shareholders' investments.

6.3.3 The present SCAs are due to expire in 2018, and the Government is in the process of deciding whether alternative methods of regulating the electricity market could be more appropriate for Hong Kong in the post-2018 period.

6.3.4 The Hong Kong Environment Bureau are tasked with monitoring the SCAs, by assessing Development Plans relating to the provision and future expansion of the electricity supply systems of HEC and CLP to ensure the investments made are not excessive, premature and unnecessary. It also performs annual tariff reviews jointly with the power companies to ensure tariff adjustments are reasonable and to agree on changes from those approved in the Development Plans if applicable.

6.4. Scheme of Control Agreements

6.4.1 The SCAs that the Government currently hold with CLP and HEC are designed to reflect the Government's policy objectives of ensuring the public to continue to enjoy reliable and safe electricity supply at reasonable prices, and to minimise the environmental impact caused by the production and use of electricity. The agreements cover a ten year period, with an option for the Government to extend the SCAs for five years dependent on prevailing market conditions, including the potential for new supply sources.

6.4.2 The current SCAs began in 2008 and will expire in 2018 unless the Government exercises the option for a five year extension until 2023.

Net and Permitted Return

6.4.3 The objectives of the current SCAs are to ensure that the power companies provide a reliable and safe electricity supply to the consuming public at a reasonable price and that the shareholders of the companies obtain a reasonable return on their investment.

Rate-Of-Return

6.4.4 The permitted rate of return of the power companies is 9.99% on Average Net Fixed Assets (ANFA). Separately, financial incentives are provided to the power companies for improvements in energy efficiency, operational efficiency, supply reliability and customer services, while disincentives are included to discourage under-performance. The ceiling of these incentives in total is capped at 0.05 percentage point above the rate of return.

6.4.5 To encourage the use of renewable energy (RE), investments on RE facilities can earn a higher rate of return of 11%. In addition, power companies are provided with incentives of additional return (0.01 to 0.05 percentage point) for electricity generation by RE according to a specified scale.

Tariff Stabilisation Fund

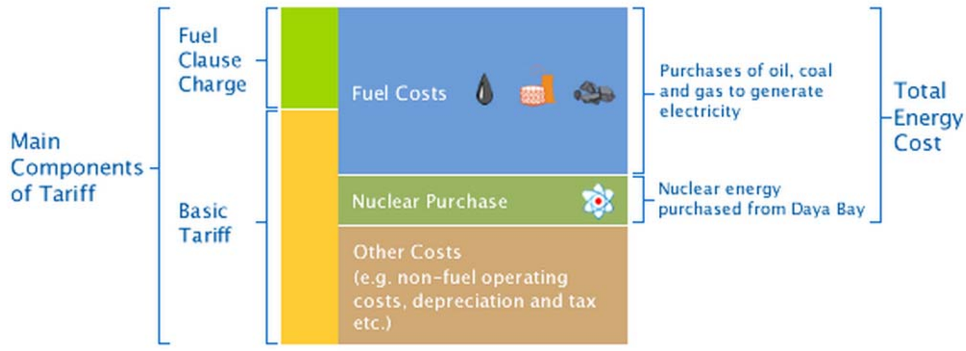
6.4.6 The Tariff Stabilisation Fund (TSF) is maintained for the retention of Gross Tariff Revenue in excess of the Total Operating Costs, permitted return and tax, which when necessary will provide funds to ameliorate the impact of tariff increase for consumers or facilitate tariff reduction where appropriate. The cap on TSF balance is revised from 8% to 5% of annual local sales revenue with effect from 1 January 2014 as agreed in the SCA

Mid-term Review completed in 2013. Separately, the interest charge on the average TSF balance is set at short term market interest rates. The TSF does not form part of distributable shareholders' funds and represents a liability in the accounts of power companies.

Fuel Clause Charge

6.4.7 The Fuel Clause Charge is a charge/rebate for the difference between the standard cost of fuels as agreed between the companies and the Government and the actual cost of fuels, as forecast in the Tariff Review. This difference is passed through to the end-consumer by adding it to the Basic Tariff. When the forecast fuel cost is different from the actual fuel cost, the variance is maintained in a Fuel Clause Recovery Account.

Figure 18: Components of CLP Electricity Tariff



Source: CLP Power

Review Processes

Tariff Review

6.4.8 In October of each year, a tariff review is conducted jointly by the Government and the companies. Projections for the current year will take into account an upper limit on the projected year-end TSF balance, with a one-off rebate or tariff adjustment applied in the year following to reduce any excess to the limit. The upper limit is set at 5% of annual total revenue from local electricity sales for each company.

6.4.9 Under the SCAs, if the proposed Basic Tariff Rates do not exceed those approved by the Executive Council for the relevant year in the prevailing Development Plan by more than 5%, the power companies are entitled to implement the Basic Tariff Rates for the year without the need for Government's approval. The power companies are also required to disclose their projected Basic Tariff Rate profile to the public upon approval of the Development Plan by the Executive Council.

Development Plan Review

6.4.10 In order to establish agreement concerning the companies' projected Basic Tariff, reviews of the companies' Development Plans are conducted by the Government jointly with each of the companies. Under the SCA, the regulated companies must submit Development Plans six months before the period covered by the previous Development Plan expires, which include information about revenue and capital budgets, previous and current years' financial models, the forecast demand, fuel costs and sales of the company, and all current and projected operating and capital expenditures. Following approval by Executive Council, the power companies will make available to the public projected Basic Tariff Rate profile plus supporting information.

Auditing Review

6.4.11 In order to monitor the financial performance of the power companies under the SCAs, the Government performs an Auditing Review. This is conducted yearly and the companies must submit documents no later than three months after the close of the company's financial year. The auditing review is also conducted to monitor technical and environmental performance of the companies' energy efficiency and conservation programmes, on which the companies' performance incentives are based.

Incentive and Penalty Adjustments

6.4.12 Adjustments in respect of performance relating to emissions, energy efficiency, operational efficiency and customer service are made to the permitted level of return of 9.99% to give the total annual net return of the power companies. There are five different adjustment mechanisms, all of which adjust the rate-of-return by varying amounts depending on performance. The companies are rewarded for achieving and outperforming these targets and face penalties if they do not meet them.

Table of Incentive/Penalty Adjustments

6.4.13 The table below shows the various incentive/penalty targets currently present within the SCAs, and the amounts by which achieving or failing to meet these targets adjusts net permitted return for each of the power companies.

Table 8: SCA Incentive/Penalty Adjustments

Performance Category	Index	Target	Incentive Adjustment
Emissions Performance [only HEC]	Emissions Performance Linkage Mechanism	If Total Permissible Emissions (TPE) for one or more pollutants is exceeded by 30% or more	-0.4%
		If TPE for one or more pollutants is exceeded by 10% or more but none of the TPE of any pollutant is exceeded by more than 30%	-0.2%
		If none of the TPE of any pollutant is exceeded by 10% or more but every TPE excluding market adjustment is outperformed by 10% or more	0.0%
		If TPE excluding market adjustment of all pollutants are outperformed by 10% or more, but less than 30%	+0.05%
		If TPE excluding market adjustment of all pollutants are outperformed by 30% or more	+0.1%
Supply Reliability	Average Service Availability Index (ASAI)	99.995% ≤ ASAI	+0.01%
		99.99% < ASAI < 99.995%	0%
		ASAI ≤ 99.99%	-0.01%
Operational Efficiency	Connection & Supply Performance Index (CSPI)	CSPI = 100%	+0.01%
		99.98% < CSPI < 100%	0%
		CSPI ≤ 99.98%	-0.01%
Customer Services	Appointment Punctuality Index (API)	99.7% ≤ API	+0.01%
		98% < API < 99.7%	0%
		API ≤ 98%	-0.01%

Table 8: SCA Incentive/Penalty Adjustments

Performance Category	Index	Target	Incentive Adjustment
Energy Efficiency	Energy Saving Incentive Factor	HEC: 3GWh ≤ Energy Saving Performance	+0.01%
		CLP: 12GWh ≤ Energy Saving Performance	
	Energy Audit Incentive Factor	HEC: 50 ≤ number of energy audits under Energy Audit Programme	+0.01%
		CLP: 150 ≤ number of energy audits under Energy Audit Programme	
Renewable Energy	Renewable Energy Incentive Factor	5% ≤ % RES-e of total generation	+0.05%
		2% ≤ % RES-e of total generation < 5%	+0.03%
		1.5% ≤ % RES-e of total generation < 2%	+0.02%
		1% ≤ % RES-e of total generation < 1.5%	+0.01%
		% RES-e of total generation < 1%	0.0%

Source: Hong Kong SCAs, 2013 SCA Mid-term Review (25/11/2013)

Emissions Performance Linkage Mechanism

6.4.14 The Emissions Performance Linkage Mechanism, which is currently only applicable to HEC, operates on the basis of Total Permissible Emissions for the applicable year in respect of pollutants including sulphur dioxide, nitrogen oxides, and respirable suspended particles. The Total Permissible Emissions allowed for each pollutant is the maximum amount of a pollutant expressed in tonnes that all power plants owned and operated by the companies are allowed to emit as set out in a Specified Process Licence. This takes into account any emission allowance or credits obtained from third parties through emissions trading, these allowances are referred to as market adjustments. The level of Total Permissible Emissions determines the incentive or penalty adjustment made to the net permitted return, as shown in Table 8.

Customer Performance Incentives / Penalties

6.4.15 **Supply Reliability** – The reliability of supply is measured by calculating the Average Service Availability Index (ASAI) achieved by each of the companies in relation to that year. This is the proportion of time per year that the system has performed uninterrupted expressed as a percentage. The result of the ASAI determines the incentive adjustment made to the net permitted return, as shown in Table 8.

6.4.16 **Operational Efficiency** – The operational efficiency is measured by calculating the Connection and Supply Performance Index (CSPI) achieved by the each of the companies. This is the proportion of Satisfactory Installation Inspection of premises that were successful in connecting premises to the network. The result of the CSPI determines the incentive adjustment made to the net permitted return, as shown in Table 8.

6.4.17 **Appointment Punctuality Index** – The Appointment Punctuality Index (API) is the proportion of appointments that were successfully attended by a member of the company with whom the appointment had been scheduled. The result of the API determines the incentive adjustment made to the net permitted return, as is shown in Table 8.

Energy Efficiency and Renewables Incentives / Penalties

6.4.18 Energy Efficiency financial incentives are centred on energy saving and energy audit. The Energy Saving Incentive Factor requires energy saving performance, defined as the aggregate energy saving, expressed in GWh, attributable to energy-saving technologies assessed on an engineering design basis installed in that year by customers of the companies. The Energy Audit Incentive Factor rewards the companies for performing sufficient number of energy audits under the Energy Audit Programme – an audit by the power companies of their industrial and commercial customers' energy requirements based on Guidelines on Energy Audit issued by the Electrical and Mechanical Services Department of the Government.

6.4.19 The Renewable Energy Incentive seeks to encourage renewable generation, using incentives based on the percentage of electricity generated by renewable energy sources.

Test for Excess Generating Capacity

6.4.20 Any additional unit of generating capacity added in a particular year – excluding renewable energy systems and combined cycle gas generation units installed to meet emission requirements – shall be subject to an overall test comprising of the Excess Capacity Threshold (ECT) test and the Reserve Capacity (RC) test in the year in which each additional unit's commissioning takes place. These two tests are designed to ensure there is no excess capacity in the generating system. If an additional unit fails either test, it shall be subject to another overall test in each subsequent year until it passes either test.

6.4.21 The ECT test uses the criterion of the Loss of Load Probability (LOLP)[69], and any additional unit will pass the ECT test if the ECT LOLP in the year of commissioning of the additional unit is found to be equal to or above the target LOLP adopted for planning the installation of the unit.

6.4.22 The RC test establishes whether the reserve capacity available before commissioning of the additional unit exceeds the reserve capacity requirement. If this is the case, the additional unit will fail the RC test.

6.4.23 In the case of the ECT test and RC test both being failed for two successive years, an Excess Capacity Adjustment is deducted from the permitted return of the second year and each of the following years, up to but excluding the year in which the additional unit passes either test.

6.4.24 Under the SCAs, 50% of the net asset value on mechanical and electrical equipment relating to new generating facilities that are found to be in excess to meeting electricity demand is excluded from the company's ANFA for calculating the permitted return. This penalty is removed when demand catches up with generation capacity, and does not apply to renewable energy assets.

[69] LOLP is a measurement of a system's reliability and security of generation. It measures in terms of days or hours per year, the probability of the generation system not meeting the demand. LOLP of a year is sum of the probabilities of every combination of generation unit being out of service which will result in operating capacity being less than the maximum demand for a given hour or day in the year, where actual local maximum demand is calculated as 104% of peak demand.

7. PSM SUITABILITY FOR THE HONG KONG MARKET POST-2018

7.0 There are currently four policy goals laid out by the HK Government for the electricity sector[70]:

- **Safety** – ensuring that electricity is generated, transmitted, distributed and used in a safe manner;
- **Reliability** – ensuring a stable electricity supply with minimal unplanned electricity interruptions;
- **Affordability** – ensuring that electricity is provided at a reasonable price to consumers; and
- **Environmental performance** – ensuring the minimisation of air pollution and carbon emissions.

In this section, we examine each of the PSMs specific to Hong Kong's circumstances and in context of these policy goals.

7.1. Rate-of-Return Regulation

7.1.1 In Section 3.2, we introduced rate-of-return regulation, and its theoretical advantages and disadvantages, which in summary are:

- Incentivises investments, as prices stay in line with costs;
- High-quality and safety are therefore likely;
- Possibility of excessive investments; and
- Weak incentives for productivity improvement.

7.1.2 The Hong Kong electricity market has been regulated based on rate-of-return regulation, which is implemented through bilateral SCAs with the two power companies, detailed in Section 6.4. The SCAs contain several components that help ensure the policy goals of the Hong Kong government are met. Table 9 below summarises the compatibility of rate-of-return regulation, and more specifically the SCAs, achieve these goals.

Table 9: Suitability of rate-of-return regulation in Hong Kong

Policy goal	Suitability in Hong Kong
Safety and reliability	✓ Incentives for investments help maintain current safety standards and reliability of supply
Affordability	× Tariffs linked to level of investment, which in theory could lead to higher tariffs, but can be mitigated through monitoring and scrutiny of investment proposals
Environmental Impact	✓ Incentives for environmental performance targets such as promotion of energy efficiency and savings directly can help achieve environmental objectives

Source: IPA analysis

[70] Environment Bureau (2014): *Future Fuel Mix for Electricity Generation Consultation Document*

7.1.3 Below, we examine in detail how well the rate-of-return regulation, as laid out in the SCAs, meeting Hong Kong's electricity policy goals.

Safety and reliability

7.1.4 The reliability of supply in Hong Kong is very high, being consistently over 99.999%[71]. This can be largely attributed to the rate-of-return regulatory regime, which incentivises investment and development of generation facilities and supply networks. This has a positive knock-on effect on safety as a return is also earned on investments to meet safety standards.

7.1.5 Contributing to the reliability of supply in Hong Kong are the high reliability standards, for which incentives and penalties are provided for within the SCAs. Power companies are rewarded by way of a 0.01% increase in permitted return if they achieve supply reliability of over 99.995%, and penalised by way of a 0.01% decrease if supply reliability is lower than 99.99%.

Affordability

7.1.6 While a major benefit of rate-of-return is that it will encourage investment, it runs the risk of providing an incentive structure for companies to over-invest in order to increase their regulated asset base and earn a higher return (i.e. gold-plating). This could occur through investing in unnecessary infrastructure. Or they may also invest in infrastructure at a higher cost instead of going for the most-economic and least-cost options.

7.1.7 As the profits of the companies are not linked to any productivity or efficiency gains, the rate-of-return regime also does not provide any explicit incentive for the power companies to reduce their costs by enhancing productivity and efficiency.

7.1.8 In theory, the above downside risks associated with the rate-of-return regime can result in higher tariffs. However, having examined the trend of movement of electricity tariffs in Hong Kong and its comparison with those in other regimes, there has not been any concrete evidence to suggest that such problem exists in Hong Kong. In November 2013, the residential tariff in Hong Kong of approximately HKD $1 compared favourably with those of other major cities in the world, including those which adopt other PSMs such as cap regulation, such as Singapore, London and New York which had tariffs equivalent to HKD $1.74, HKD $2.04 and HKD $2.30 respectively.[72] Similarly, in terms of electricity expenditure, Hong Kong compares favourably with electricity expenditure on average accounting for less than 2% of household spending, when compared to 2.7%, 2.4% and 2.7% in Singapore, the UK and the USA respectively.[73]

7.1.9 The relatively stable tariff could be attributed to a number of mechanisms that have been put in place in the regulatory regime in Hong Kong. In case of a company earning a greater (or lower) rate-of-return than permitted in one year, the SCAs contain the provision of a Tariff Stabilisation Fund (TSF), which allows the companies to transfer disallowed (or below the allowed) returns to (from, provided there is an adequate balance) the TSF which is used to mitigate tariff adjustments, and ultimately belongs to the consumers. This works as an effective tool in smoothing out any price shocks resulting from the volatility of fuel or other non-controllable costs.

[71] Environment Bureau (2014): *Future Fuel Mix for Electricity Generation Consultation Document*
[72] CLP *2014 Development Plan and 2014 Tariff*
[73] Based on 2012 percentage of total household expenditure on electricity tariffs:
UK Office of National Statistics, *Expenditure on Household Fuels (2002-2012)*
US Bureau of Labor Statistics: *Consumer Expenditure Survey*
Singapore Department of Statistics: *Household Expenditure Survey 2012/13*

7.1.10 The risk of a power company in Hong Kong over-investing is also mitigated by the monitoring by the regulatory authority of the investment proposals of the power companies. Under the Development Plans (DPs) mechanism, power companies are required under the SCAs to submit investment proposals to the Government for review and approval, which are examined with the assistance of independent energy consultants. During the annual Tariff Reviews, the Government, with the support of the independent energy consultants, critically review the data on capital investment and operating costs including fuel cost, and their justifications for any adjustment to approved tariff level to ensure that the electricity tariff is maintained at a reasonable level. In addition, an annual Auditing Review is also performed to monitor the financial, technical and environmental performance of the power companies.

7.1.11 At the generation level, the risk of overinvestment is also mitigated by the SCAs with the inclusion of the Test for Excess Generating Capacity. This test seeks to discount by 50% of the overall mechanical and electrical equipment costs of any generation units from the ANFA which are deemed unnecessary to meet Hong Kong's electricity demand to limit the return earned on them.

Environmental performance

7.1.12 Under the SCAs, specific environmental performance targets in terms of promotion of energy saving and conservation have been set to encourage the power companies' performance in these areas. Linking these environmental performance targets to the rate-of-return can help achieve environmental objectives.

7.2. Cap Regulation

7.2.1 In Section 3.3, we investigated the main features of cap regulation, and its theoretical advantages and disadvantages. While it provides incentives for cost reduction and innovation, there is also the potential for supernormal profits for the companies, and without additional quality regulation it may incentivise the cutting of costs which may lead to a reduction in safety and reliability performance.

7.2.2 Adoption of cap regulation into the Hong Kong electricity market would require substantial reform of the existing framework. In the short term it is likely be disruptive to the electricity market.

Table 10: Suitability of cap regulation in Hong Kong

Policy goal	Suitability in Hong Kong
Safety and reliability	✗ Incentive to cut costs may result in reduction in safety and maintenance budget ✗ Cost efficiency may come at the price of security of supply as any capital investment may nullify efficiency gains
Affordability	✓ Aligns with HK policy objectives for increasing tariff affordability ✓ Tariffs may fall in real terms if efficiency gains are being made, given no changes in circumstances ✗ Impractical to apply inflation measure such as local CPI or RPI as a significant proportion of electricity company costs are not directly related to local inflation, giving the potential for windfall profits to power companies if applied incorrectly
Environmental Impact	✗ Does not align with HK policy objectives for reducing emissions ✗ Requires additional incentive regulation and may increase regulatory burden

Source: IPA analysis

Safety and reliability

7.2.3 Cap regulation appears less suitable than the current regulatory regime for meeting the energy policy goal in Hong Kong, which requires a high level of safety and reliability. The nature of Hong Kong's economy, as a financial centre with over 65% of electricity supply being used by commerce, places high dependency on having a reliable electricity supply. However, regulatory policy based on cap regulation may lead to a loss of quality of supply. This is because through incentivising cost reductions, underinvestment may occur to ensure costs are low enough to make a profit, although this can be mitigated through supplementary quality regulation (e.g. setting a performance standard using a reliability index). The effectiveness of the quality regulation to prevent underinvestment will vary according to its design and complexity. However, this can lead to the overall regulatory regime being complicated and burdensome, which may lead to difficulties striking a balance between cost saving incentives and output delivery incentives. Safety may also suffer as vital checks and maintenance may be cost centres that suffer from cost reductions.

Affordability

7.2.4 Cap regulation provides the incentives for lowering tariffs by mimicking a competitive market and improving cost efficiencies. In theory, as cost reductions are made, tariffs should fall in real terms and efficiency gains can be made permanent and passed on to consumers at the end of every regulatory period. Solely in terms of affordability, cap regulation provides a better control than rate-of-return over tariffs. However, there are concerns that this may be at the expense of quality of supply and reliability which, given the high standard of supply reliability, would make cap regulation not suitable for Hong Kong.

7.2.5 Pure cap regulation is also not suited for a vertically integrated electricity utility such as in Hong Kong, as a significant proportion of their costs will not be directly related to local inflation, including fuel costs. As the costs of fixed assets and internationally-imported fuel are not affected by local CPI or RPI, linking electricity tariffs to these inflation indices will result in them not being in line with actual operating costs. Furthermore, cap regulation is less valid in sectors where policies are focussing beyond affordability, such as security and decarbonisation in the generation sector.

7.2.6 Additional consideration needs to be given regarding the setting of the X factor. Ensuring that this matches the productivity growth rate of the electricity industry would be resource-intensive, as any small deviations from an effective X factor can result in supernormal profits for the companies and reduced benefits to the consumer in the way of prices. Furthermore, it may not be possible for a vertically integrated utility to reduce these costs arising from fixed costs and fuel without reduction in output and performance. This is because in the capital-intensive generation sector, they will have little or no control over these costs on an operational basis.

Environmental performance

7.2.7 The environmental performance of Hong Kong's electricity sector is unlikely to improve under cap regulation without additional incentive regulation attached, which would increase regulatory burden. Theoretically existing environmentally focused regulation used by Hong Kong could be tailored to feature within a cap regulatory framework, but this would require additional adjustments to be made to the X factor.

7.3. Sliding Scale Regulation

7.3.1 In Section 3.4, we discussed the main features of sliding scale regulation and its ability to reduce both the threat of underinvestment and also excessive profits.

7.3.2 Sliding scale regulation could theoretically be implemented in the Hong Kong electricity market. Like rate-of-return regulation, it can be applied to vertically integrated electricity utilities. Under such a scheme, the effective rate-of-return would no longer be fixed, but would vary in accordance to level of profitability in order to protect both consumers from supernormal profits and also the company from below expected returns.

7.3.3 However, there are few examples of sliding scale in practice within the electricity sector. This can be mainly attributed to the additional regulatory burden it will impose through what is essentially adding an extra layer of complication on top of the original regulation which, in reality, will be already extremely complex in practice by itself. This additional complexity is likely to be considered as an additional regulatory risk, which may result in a greater cost of capital for the electricity companies. Incorporating sliding scale regulation in Hong Kong could be difficult to implement, as it would require changing the current regime from a guaranteed rate-of-return to a variable rate-of-return that would be dependent on the absolute profit achieved. This will create risk exposure for the power companies' revenues, which is likely to result in a greater cost of capital for them. It may also be difficult to determine 'fair profit range' and what the permitted rate-of-return should be once it falls outside of this range.

Table 11: Suitability of sliding scale regulation in Hong Kong

Policy goal	Suitability in Hong Kong
Safety and reliability	× Increased risk profile due to variable rate-of-return will decrease attractiveness of investments, although this is limited by sharing mechanism
Affordability	✓ Incentives efficiency gains, whilst protecting both consumers and companies from supernormal profits/losses
Environmental Impact	× Requires additional incentive regulation and may increase regulatory burden

Source: IPA analysis

Safety and reliability

7.3.4 Sliding scale regulation could fit in with Hong Kong's policy goal of maintaining outstanding quality of supply, as it is possible to incorporate it into the current rate-of-return framework. Although sliding scale regulation does expose the regulated companies and its investors to market risks in the form of a non-definitive rate-of-return, it also limits this exposure to a degree dependent on its design. So although sliding scale regulation will affect the risk profile of new investments, which in turn is likely to affect safety and reliability, this will be to a lower degree than cap regulation as these risks are limited.

Affordability

7.3.5 Consumers in Hong Kong effectively already benefit in the form of the TSF. There is similarity in profit sharing as compared with sliding scale regulation (with no sharing of extra profit to the power companies). This accumulates returns above the permitted level and redistributes them to ameliorate tariff increases, or to facilitate tariff reductions where possible. This protects consumers from any supernormal profits by transferring profits over a permitted rate-of-return to the TSF, which belongs to consumers.

Environmental performance

7.3.6 There is no explicit regulation within the sliding scale methodology to incentivise environmental performance.

7.4. Yardstick Competition

7.4.1 In Section 3.5, we investigated the main features of yardstick regulation, and their theoretical advantages and disadvantages, the key features we identified are:

- Risk of collusion
- Structural differences between companies must be accounted for
- Quick transfer of efficiency gains to consumers

7.4.2 Given Hong Kong's market structure – namely that there are only two vertically integrated electricity utilities – yardstick competition would be difficult to implement as calculating industry average costs, after factoring in differences in company structure would be inefficient. Setting a yardstick based on a 'model' company for costs, reliability and even environmental performance may achieve improvements in these policy areas, but considering the existence of bilateral agreements that are designed with these policy goals in mind it would seem unnecessary. Furthermore, it would be extremely difficult to calculate costs of such a 'model' company for benchmarking, due to lack of information as Hong Kong has been served by two power companies under SCAs for decades.

7.4.3 Yardstick competition is at risk from collusive practices by companies to force the yardstick to be artificially set above the optima level. The chance of market collusion increases as the number decreases, and Hong Kong therefore would be greatly exposed to such a risk. Yardstick competition also works under the assumption that the regulator is fully committed to the regulatory contract – namely that there is no scope for discretionary intervention. This implies that companies that are outperforming the yardstick earn supernormal profits, and those that are not are allowed to go bankrupt. Regulatory commitment of this level would not work in Hong Kong as if either of the power companies were to go bankrupt due to yardstick regulation and risk supply reliability it would be deemed failure on the part of the regulator.

Table 12: Suitability of yardstick competition in Hong Kong

Policy goal	Suitability in Hong Kong
Safety and reliability	– Can incentivise safety improvement if yardstick is set for safety standards and quality of supply ✗ Difficult to set with so few market participants
Affordability	✗ Would not necessarily improve current tariffs due to lack of comparators
Environmental Impact	✗ Requires additional incentive regulation and may increase regulatory burden

Source: IPA analysis

7.5. Conclusions of PSM Suitability for Hong Kong

7.5.1 Based on our understanding of the Hong Kong electricity system in context of its policy goals and the past performance of the electricity supply, rate-of-return regulation based on the current SCAs appears to be the most suitable post-2018. Not only is it the easiest to implement, due to its current usage, but it provides distinct advantages over other price setting mechanisms in meeting Hong Kong's policy goals. There is also no concrete evidence to suggest that there has been any problem associated with the rate-of-return approach currently employed in Hong Kong.

7.5.2 Given Hong Kong's need for a high degree of reliability, rate-of-return regulation provides the necessary incentives and protection from market risks to incentivise electricity companies to invest. This further applies to the Hong Kong's policy of reducing the environmental impact of the electricity sector, as rate-of-return will also incentivise investment in energy efficiency and conservation.

7.5.3 The major weakness of rate-of-return regulation is that it does not incentivise cost efficiencies. However, the analysis above shows that there are currently tests within the SCAs to mitigate against over-investment, and the monitoring exercised by the regulator has been effective in keeping the Basic Tariff at a relatively stable level with the extent of increase below that of the CCPI. There is scope for additional measures to improve this, which we explore in Section 8.

Table 13: Summary of applicability of PSMs for Hong Kong

Policy goals Criteria	Rate-of-return	Cap regulation	Sliding scale	Yardstick
Ease of implementation in Hong Kong	✓	×	-	×
Safety and reliability	✓	×	×	×
Affordability	×	✓	✓	×
Environmental Impact	✓	×	×	×

Source: IPA analysis

8. RECOMMENDATIONS

8.1. Introduction

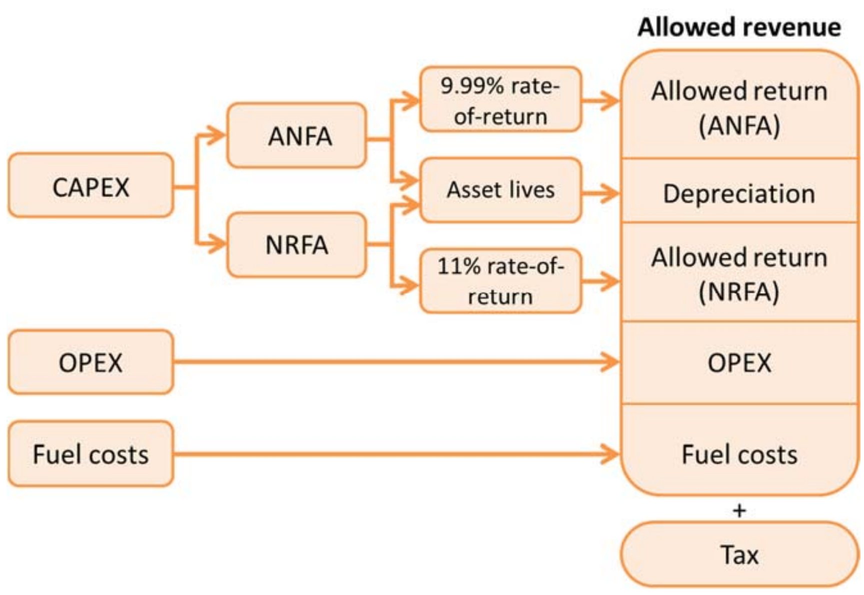
8.1.1 There are many challenges currently faced by the electricity sector in Hong Kong, primarily economic uncertainty, environmental targets and future fuel mix options. While the HKSAR Government would need to further consider the regulatory tool to be used upon the upcoming expiry in 2018 of the current SCAs between the Government and the power companies, assuming the SCAs would continue to be used, careful consideration must be made to ensure that the next SCAs will successfully deal with these challenges whilst also meeting the Government's energy policy goals.

8.1.2 The allowed revenue for the power companies can be summarised under the following categories:

- Allowed return on assets;
- Depreciation of fixed assets;
- Operating expenditure (Opex);
- Fuel costs; and
- Tax.

8.1.3 These allowed revenues are illustrated in Figure 19 below.

Figure 19: Breakdown of allowed revenue



Note: ANFA = Average Net Fixed Assets. NRFA = Net Renewable Fixed Assets.
Source: IPA analysis.

8.1.4 In this section, we examine each of these allowed revenue streams in turn and provide recommendations for possible changes to the SCAs which will allow Hong Kong to meet its electricity policy goals.

8.2. Price Setting Mechanism

8.2.1 We recommend for Hong Kong to continue using its current rate-of-return regulatory framework, with a few modifications to additional incentives to help meet policy goals.

8.2.2 The current regulatory set-up under rate-of-return has provided Hong Kong with extremely high electricity safety and quality standards to date. In theory rate-of-return regulation does not incentivise cost efficiencies, instead incentivising overinvestment. But as discussed in Section 7, there is no concrete evidence to suggest that this has been the case in Hong Kong. In practice, the tariff in Hong Kong has been maintained at a relatively stable level and the rate of increase in Basic Tariff has been lower than that of the CCPI.

8.2.3 Cap regulation is one of the main alternative PSMs used internationally in the electricity market. Designed to mimic competitive forces in a monopoly environment, cap regulation incentivises cost efficiencies. However, there is the potential for underinvestment which may lead to a fall in safety and quality performance without additional quality regulation. Furthermore, the cost of implementation is likely to be higher than staying with the current regime.

8.2.4 The key strengths and weaknesses of both rate-of-return and cap regulation are summarised in Table 14 below.

Table 14: Rate-of-return vs Cap regulation

	Key advantages	Key disadvantages
Rate-of-Return	✓ Incentivises investment ✓ Removes opportunity for excessive profits ✓ Lower cost of capital due to lower regulatory risk	× No incentives for cost efficiencies × Incentive for overinvestment × Potential for gold-plating
Cap Regulation	✓ Incentivises efficiency gains from which consumers benefit in long term	× Potential for cost reduction through underinvestment rather than efficiency gains × Focuses only on costs, requiring supplementary quality regulation × Risks of windfall profits if X factor incorrectly set

Source: IPA analysis

8.3. Allowed Return

8.3.1 In this section we provide evaluation of the current rate-of-return calculation in Hong Kong and provide suggestions on potential improvements to the process. It is the foundation of the regulation and correct setting of the rate-of-return that will ensure any adjustments or additions to the SCAs have a higher probability of functioning correctly.

WACC

8.3.2 As seen in Section 4, WACC is commonly used in both cap and rate-of-return regulation to establish a reasonable rate-of-return on a fixed asset base. The current rate-of-return in Hong Kong was set following an initial WACC calculation which led the Government to propose a permitted rate-of-return of 7%-11%. Following negotiation between all parties, the rate-of-return was established at 9.99%.[74]Members of the Legislative Council of the HKSAR have since raised the issue that this permitted rate-of-return is still too high and needed to be further reduced, but this was rejected by the power companies at the 2013 Mid-Term Review[75].

8.3.3 We recommend continuing to derive the rate-of-return from a WACC calculation. This is a commonly used method internationally, which would provide a justified and fair rate-of-return that would adequately cover the cost of capital of the companies.

RAB

8.3.4 There are two basic approaches to calculating Average Net Fixed Assets (ANFA), from which the return is calculated:

- **Asset base approach** – this links return to the value of the aggregated assets (return on asset or ROA); or
- **Equity base approach** – this uses shareholders' funds (i.e. aggregate assets minus liability) as the base to determine the return (return on equity or ROE).

8.3.5 The asset base approach is currently used. This was a matter of debate for the Stage 1 Consultation in 2005[76], where respondents expressed a greater preference towards using an asset base.

8.3.6 We recommend the continuation of using an asset base for the calculation of returns. Although this may incentivise over-investment, this can be mitigated. Furthermore, even though the alternative equity base approach would encourage shareholders to inject funds for investment, it would likely result in inefficient financing as it de-incentivises the use of debt capital due to loans or bonds being excluded from the RAB.

Mitigation against over-investment

8.3.7 Rate-of-return regulation incentivises over-investment. There are provisions within the SCAs to address this: the Test for Excess Generation Capacity mitigates against development of excess capacity, and the submission and review of the Development Plans helps to mitigate against unnecessary investments.

8.3.8 In order to ensure cost-effective investments, following three principles should be applied:

- **Economy:** minimising the cost of resources used or required (inputs) (i.e. spending less);
- **Efficiency:** the relationship between the output from goods or services and the resources to produce them (i.e. spending well); and
- **Effectiveness:** the relationship between the intended and actual results of spending (outcomes) (i.e. spending wisely).

8.3.9 These three principles, along with information flows, are illustrated in Figure 20 below.

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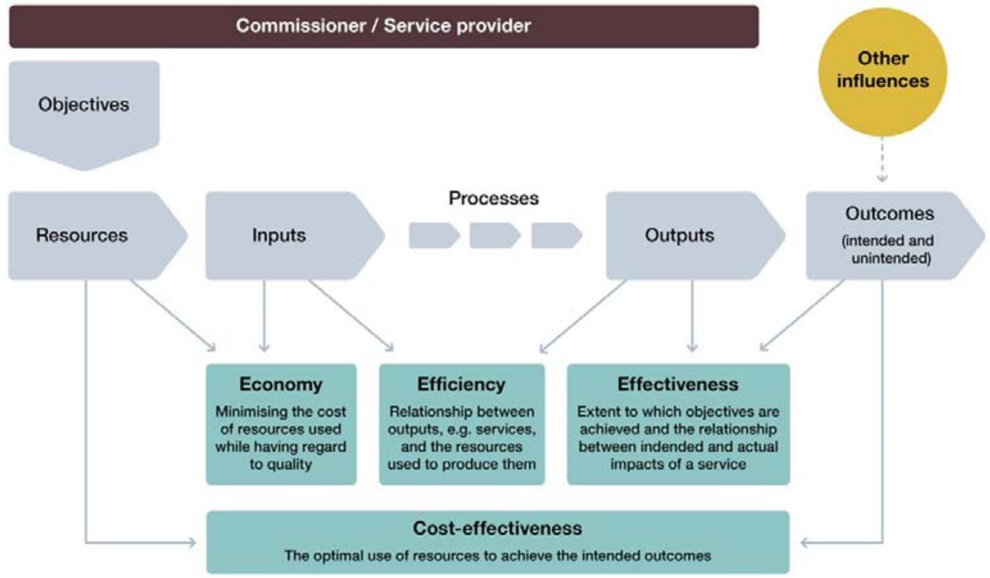
[74] Legislative Council Panel (2008) – New Scheme of Control Agreement with the Two Power Companies

[75] Legislative Council Panel (2013) – Scheme of Control Agreements (SCAs) with the Power Companies: 2013 SCA Mid-term Review

[76] Legislative Council Panel (2005) – Future Development of the Electricity Market in Hong Kong: Views received during the Stage I Public Consultation

Figure 20: Value for money criteria



Source: [*UK National Audit Office*]

8.3.10 It is observed that these principles are applied in the following manner for the Hong Kong electricity sector:

- **Economy** – ensuring that new infrastructure is necessary. This is addressed in the Test for Excess Generating Capacity and the independent review of the Development Plans by consultants to verify the need of proposed investments;
- **Efficiency** – procurement of services to build infrastructure at the lowest cost. Power companies are procuring their equipment or installation through public tender. During the review of Development Plan, project costs are benchmarked against the costs of comparable developments in other jurisdictions to ensure money is spent efficiently; and
- **Effectiveness** – ensuring that new infrastructure is the economically least-cost solution to deliver generation/transmission/distribution. This is done through the review of the Development Plans, requiring an independent consultancy study to corroborate that it is cost-effective.

8.4. Depreciation

8.4.1 Depreciation is allowed for fixed assets. These costs are non-controllable by the electricity companies, as the treatment of depreciation is clearly defined within the SCAs. We recommend that the current method of depreciation is applied in the new SCAs post-2018.

8.5. Opex

8.5.1 Under current SCA arrangements, Opex costs are passed through and ultimately borne by consumers. However, there is scope for some of these costs to be reduced, which can contribute to lower electricity tariffs.

8.5.2 Opex items can generally be broken into two main categories.

- *Non-controllable Opex* – includes government rent and rates, insurance and fuel costs.
- *Controllable Opex* – includes staff hires, materials and services.

8.5.3 By their very nature, non-controllable Opex is outside of control for the electricity companies, and so we will not examine this further. However, there is scope to reduce the costs for controllable Opex items, as discussed below (fuel costs are discussed in subsection 8.6).

Controllable non-fuel Opex

8.5.4 As with any commercial entity, there is scope for a business to be optimised and costs reduced. In a competitive environment, market forces prompt these to naturally occur, as firms compete to ensure they are able to sell more products through lower prices. In a monopoly, this will only occur if the regulation includes an incentive for cost efficiencies.

8.5.5 Under the current SCAs, all Opex items are passed through, leaving no incentive for the companies to control them. If cap regulation were to be applied to controllable Opex items (excluding fuel costs), it would provide an incentive for companies to earn greater revenues through cost efficiencies, and these savings would ultimately be passed to consumers. A fair price setting structure could be calculated by determining a starting pass-through cost based on historic costs, then subjecting it to an inflation index minus a productivity factor.

8.5.6 Applying such a regime would require choosing an appropriate inflation index and productivity factor:

- **Inflation index** – one option would be to base the index on the industry wage index (calculated in a similar way to how the transport wage index is calculated and used as a basis for MTRCL and franchised buses fares in Hong Kong). However, this would appear to be not be very meaningful for electricity sector in Hong Kong as there are only two power companies, which raises the possibility of gaming. It would also not be appropriate to simply use CPI or RPI, given that the majority of costs are not directly related to these inflation indices.
- **Productivity factor** – if applied, this could be based on historical efficiency gains (output/input ratios) from prior regulatory periods.[77] For the transport sector, a sharing factor with consumers of 50% is applied in the case of franchised buses, to create incentives to make further cost reductions.

8.5.7 However, it should be noted that controllable non-fuel Opex currently constitutes less than 10% of the Net Tariff, of which staff costs constitute a significant part. The proposed arrangement will therefore only have limited impact on the tariff adjustment.

8.6. Fuel Charging Arrangements

8.6.1 We note that fuel costs account for a significant portion of the regulated tariff and has been the primary cause of tariff adjustments in recent years. We also note that this is mainly due to the replacement of previous gas contracts upon expiry of new ones at current market prices which are much higher, coupled with the increased use of gas-fired generation to displace coal power plants for better air quality.

8.6.2 We understand that under the current SCA regime, ENB checks that the power companies have implemented adequate corporate governance in their procurement procedure during the annual Auditing Review. In the Development Plan and the Tariff Review exercises, an independent energy consultant is engaged to check the power companies' forecast fuel

[77] Following the methodology employed in the calculation of the productivity factor for the Hong Kong MTR, output is defined as revenue, and input is defined as operating expenses (before depreciation, amortisation and variable annual payment expenses) earned/incurred in the MTRCL's Hong Kong transport operations, as set out in their audited financial statements.

prices by benchmarking the fuel prices against global trends. In vetting the long-term gas contracts, which are approved by the Executive Council in view of their stranded costs implication, the independent energy consultant would assess whether the price formula is in line with international practice and the reasonableness of projected gas price.

8.6.3 Without subsidising fuel costs, it will be almost impossible to shield consumers from rising fuel costs on the international market. However, the SCAs should ensure that the electricity companies are incentivised to procure fuel inputs at a competitive rate, and minimise volatility of fuel costs.

8.6.4 To incentivise this, we recommend that the SCAs contain the following provisions:

- **Companies must demonstrate that fuel is procured economically** – companies must prove that they have procured fuel at a competitive market rate, for verification by an independent energy consultant. This form of regulatory oversight will ensure that companies are incentivised to minimise the cost of fuel and hence also electricity supplied to consumers. It is observed that measures have been taken in Hong Kong to ensure the companies to demonstrate that fuel is procured economically in the Tariff Review and Development Plan assessment through the verification by independent consultant.

  Companies should minimise their fuel cost volatility – Companies may also be able to minimise fuel cost volatility through the purchase of long and short term forward contracts, or other means such as hedging. By locking in future prices, hedging allows companies to reduce uncertainty in their fuel costs, which can aid cash flow budgeting whilst insulating consumers from spikes in market prices.

8.6.5 However, hedging has its downside risks and cannot guarantee a net benefit in fuel savings: if market prices increase more than expected, it will result in savings to consumers; conversely, if market prices fall greater than expected, additional costs will be incurred in the procurement of fuel[78]. Hedging comes with its own complexities, and it is not straightforward to determine an appropriate hedging strategy, especially when market prices undergo significant changes, as experienced in 2014 Q4. Although there are potential savings to be gained during periods of upward price movements, incorrectly placed hedges can result in significant losses, as experienced by some operators in the airline industry, in 2008 and 2014 as a result of falling fuel prices during these years. Under a pass-through arrangement, the risk associated with the hedging would also be ultimately shouldered by the consumers. The administrative costs of hedging, from setting up future trades, broker fees and the formulation and implementation of a hedging strategy, need to be taken into account and considered against the benefits when deciding whether hedging is an appropriate choice for fuel procurement. This process of ensuring the fuel is sourced competitively as a result of market transition is not uncommon. In Denmark, as the market was liberalised, the former state utility – DONG Energy – moved from favourable long-term gas contracts, secured when it was state-sponsored, to new contracts at market rates, fuel prices were managed through a new trading function within DONG Energy which managed the procurement of fuel and price volatility through hedging. This would have enabled fuel to be procured at favourable conditions relative to the market, taking advantage of changes in forward market prices, resulting in reduced

[78] The adoption of hedging may be open to political risk, as people value gains and losses differently, being more sensitive to losses than they are to gains. If market prices were to fall below hedged prices, then power companies may face consumer pressure to reduce prices as fuel could have been procured at a lower cost, in what is perceived as an effective loss (this is treated as an ‘unrealised loss’ in accounting). However, if prices were hedged when prices are low and market prices were to increase, the effective gains through savings in fuel costs are unlikely to receive an equivalent level of praise, as this would be an expectation of hedging. Thus, procuring fuel at market rates is likely to be perceived more favourably than a hedging strategy which results in both gains and losses.

costs for consumers. In Ireland, as the energy retail market was nearing full liberalisation in 2005, the Commission for Energy Regulation (CER) needed to ensure that power generated by the Electricity Supply Board (ESB) was bought by its affiliate, the ESB Public Electricity Supplier (PES), at a fair economic price. CER achieved this by creating an Economic Purchase Obligation (EPO). The EPO prevents ESB and PES from agreeing prices that do not represent the market rate. This is achieved by the submission of contract details by ESB and PES to CER for approval, with an approval decision being based on whether there is sufficient evidence to demonstrate that the contracts are fair, transparent and at an economic price, ensuring least-cost for consumers based on available market rates. It is still in use today and requires that any wholesale electricity contracts agreed between ESP and PES provide price stability, the best value for customers, and does not discriminate between any customer (and class of customer).[79]

8.7. Environmental Performance

Renewable targets

8.7.1 Increasing renewable energy requirements would undoubtedly improve the environmental impact that the electricity sector has on Hong Kong, but incentivising such a policy is difficult considering the initial costs involved with renewables. An increase in the permitted rate-of-return on renewable assets may attract greater investment in that sector as investors seek higher returns. However, recent experience in Hong Kong shows that providing a higher return to RE asset and investment by power companies is not conducive to promoting the development of RE, as the high cost of RE will result in a tariff impact. Other measures are required to effectively incentivise the investment in RE technology.

8.7.2 Energy subsidies rather than price regulation are more commonly used in the GB market and other EU states to encourage renewables investment. However there is a case for using the renewables permitted rate-of-return to encourage further investment in the sector, and improve the environmental impact of the electricity sector on Hong Kong. This must be considered carefully however as an increase in renewables rate-of-return could negatively affect affordability of tariffs.

8.7.3 There are other factors which can affect the deployment of renewables more than rate-of-return. Of these, the most important are regulations which protect renewable generators against market risk, namely priority grid dispatch, guaranteed transmission connection and guaranteed revenues (e.g. feed-in tariffs).[80]

Energy efficiency

8.7.4 Under rate-of-return regulation, utilities have an economic disincentive to provide programmes to help their customers be more energy efficient. Energy efficiency measures, although included as incentive factors within the SCAs, could perhaps be addressed more directly towards the power companies.

[79] Irish CMA (2010): *Competition in the Electricity Sector*

[80] Priority grid dispatch – any electricity generated by those with priority grid dispatch will automatically be purchased ahead of other plants, regardless of supply/demand fundamentals and other costs to the system.

Guaranteed transmission connection – the installation gets the permission to build a connection to the grid allowing to actually feed the electricity produced into it.

8.7.5 Demand side management targets will depend on technologies available to the utilities and require study of users and end-uses of electricity. The current Energy Savings and Energy Audit Incentive Factors seek to incentivise energy efficiency promotion within large commercial customers through installation of recognised energy saving technologies. Improving these targets to include a wider span of customers or target the least energy efficient customers could enhance demand side management targets and potentially smooth load on the system increasing the power companies' ability to forecast demand and manage operating costs accordingly. This should aid tariff predictability and stability in the medium term.

Energy Efficiency Promotion in the UK

In line with the EU Energy Efficiency Directive, the UK Government has introduced a number of policies to improve energy efficiency. These energy efficiency schemes require energy measurement and/or energy auditing, and are:[81]

- **Carbon Reduction Commitment Energy Efficiency Scheme** – this is a mandatory scheme aimed at large, but non-energy intensive public and private sector energy users to encourage organisations to prioritise investment in energy efficiency and cut carbon emissions. It uses tailored combination of drivers, including a carbon price, mandatory standardised monitoring and reporting of energy consumption to raise awareness of energy use at Board level, along with publication of enterprises' aggregated emissions data.
- **Mandatory Greenhouse Gas reporting** – this requires compulsory comment on greenhouse gas emissions including energy emissions for all quoted companies for their entire organisation to be included in their annual reports. This report is mandatory unless an explanation can be given as to why such a report is not necessary. The introduction of these reports is intended to inform investors as to whether companies are efficiently managing potential hidden long-term costs of greenhouse gas emissions.
- **Climate Change Agreements** – these act as an incentive for energy-intensive industries, covering around 9,000 facilities, to meet energy efficiency targets with the reward of tax discounts (worth £170 million a year). Targets are set using evidence submitted by industry on abatement potential.
- **Energy Performance Certificates** – these present energy efficiency ratings of domestic and non-domestic buildings on a scale from A+ to G, based on an assessment of the age, size and fabric of the building. These were introduced as part of the EU Energy Performance of Buildings Directive and must be made available whenever a property is constructed, rented or sold.
- **The Green Deal** – this supports households to install energy efficiency measures, including insulation; draft-proofing; improved heating controls; double glazing; and renewable energy technologies such as solar panels. It conducts via means of a two stage independent assessment of potential household energy efficiency: the first stage is based on an existing Energy Performance Certificate, which is mandatory on sale of a property, and the second stage is a report based on actual occupancy information which identifies cost effective measures to improve energy efficiency.

8.7.6 Another measure to improve energy efficiency are Revenue-neutral Energy Efficiency Feebates (REEF) in which an allowed amount of energy consumption is established for customers and those who use more than the allowed amount pay an extra fee. This is used

[81] UK Department of Energy and Climate Change: *UK National Energy Efficiency Action Plan (2014)*

to rebate customers who use less than the allowed amount of energy. This is similar to a progressive tariff structure employed by some power companies, where those who consume more energy are required to pay a unit rate much higher than those who use less, resulting in reduced increases in electricity demand.

8.7.7 Implementing demand side management in Hong Kong is a possibility, although would require agreement from the power companies and could potentially increase regulatory burden. Demand side management or use of policies such as REEF would increase administrative costs but may improve the environmental impact of energy consumption in Hong Kong.

Emissions Performance Linkage Mechanism

8.7.8 As highlighted in the Clean Air Plan by the Environment Bureau in 2013, air pollution reduction is a high priority in Hong Kong.

8.7.9 Emission caps are now imposed on the power stations in Hong Kong through the promulgation of Technical Memorandum (TM) under the Air Pollution Control Ordinance (Cap. 311), gazetted in October 2014. The new TM caps the annual emissions of sulphur dioxide (SO_2), nitrogen oxides (NO_x) and respirable suspended particulates (RSP) from the power generation sector from 2019 at 9,220 tonnes, 25,480 tonnes and 700 tonnes respectively. Compared to the corresponding emission caps in the third TM for 2017 onwards, the emissions of these three air pollutants will be reduced by 11 per cent, 2 per cent and 7 per cent respectively.

8.8. SCA Structure

8.8.1 Since their inception in 1963 the SCAs have been reviewed and updated to arrive at their current form. In Section 6.4 we reviewed the function of the current SCAs and below we evaluate some of the recently discussed and most relevant areas of the SCAs. We look at how developments in the electricity market could require that the SCAs are changed to react to these developments without undermining the regulatory framework.

SCA duration

8.8.2 The decision for the current SCAs to cover a ten year period allows for greater long term planning for the companies without fear of change in the rate-of-return or the regulatory framework. This benefits both the company and the consumer as longer term planning means both cost of capital and risks to reliability remain low. This helps keep tariffs stable and security of supply high, both of which are at the fore of Hong Kong’s electricity policy goals.

8.8.3 We recommend for the SCA duration to be kept at ten years with a regular review during the tenure. A downside of reducing the regulatory periods is the increase in uncertainty for investors, thus raising the cost of capital. However, the benefits of increased regulatory control through shorter regulatory periods to monitor and react to the impact of altering the regulation as well as changes to the economy may outweigh any increase in the cost of capital for the companies. For example, if the economy were to grow faster than expected, the expected rate-of-return should also increase to ensure that a reasonable return is made for investors, which would be enabled by a more frequent review of the permitted rate-of-return due to shorter SCAs. Balancing these considerations, we consider that the current regulatory period of ten years, with regular reviews during the term, should be appropriate.

Tariff approval mechanism

8.8.4 A tariff approval mechanism is triggered if the Basic Tariff is changed by 5% or more in any given year as compared with the DP forecast. The Executive Council must agree to any Basic Tariff increase above 5%. Anything below that, though not requiring approval of the Executive Council, still needs to go through a Tariff Review process. This allows some regulatory freedom to the power companies and lowering this mechanism to cover every change to the Basic Tariff would perhaps signal distrust between the companies' and the Government, although it may increase accountability for all tariff increases made by the power companies. It may however be seen as overregulation as forecast tariffs are already discussed in the Development Plan reviews which occur once every five years. Furthermore, all tariff proposals, irrespectively of whether they require approval from the Executive Council, are reported to and are subject to examination by the Legislative Council, and supporting information must be provided to the public.

8.8.5 One possible improvement is that Executive Council approval should be sought if the Net Tariff increase is more than a certain percentage compared to DP forecast. This gives pressure to power companies to make more accurate fuel price forecast and to impose a requirement for them to explain significant fuel price discrepancy to Executive Council.

Reliability standards

8.8.6 The current effective reliability standard of 99.99%[82] is high, especially when compared against other financial centres. If the reliability standard was reduced slightly, it may be expected that this would translate into lower system costs. However, given that the current reliability standard is over 99.999%[83], the impact of the reliability standard might be inconsequential compared to the incentives provided by the rate-of-return mechanism for investment in the network.

8.8.7 Supply reliability is one of the obligations of the power company under the SCA. As such, the positive incentive adjustment of performance above the ASAI target could be deleted. However, we recommend the penalty adjustment is maintained to ensure reliability performance, with the penalty level to be revisited based on recent actual performance.

Test for Excess Generating Capacity

8.8.8 To ensure companies are not building excess generating capacity to inflate their ANFA, the SCAs include a test to establish whether new generating capacity is necessary. The Excess Capacity test is based on a Loss of Load Probability (LOLP) as the threshold for determining whether the new generating capacity is excessive.

8.8.9 The penalty for an additional unit of generating capacity failing the Test for Excess Generating Capacity two years in a row is that a 50% portion of the asset's mechanical and equipment (M&E) costs will not attract a net return for the shareholders of the companies, until it passes the test. The full cost of the additional unit will however remain in the asset base. Given that the companies are aware of the requirements to pass the Test for Excess Generating Capacity, the decision to set the portion of the asset's M&E costs that is unable to attract a net return at 50% may need further consideration as, if the unit is deemed excessive, disallowing a higher proportion of the asset's M&E costs from earning

[82] Based on the current SCA where companies are penalised -0.01% with their Average Service Availability Index (ASAI) is below 99.99%.
[83] Environment Bureau (2014): *Future Fuel Mix for Electricity Generation Consultation Document*

a net return may be more appropriate until it achieves the criteria to pass the Test for Excess Generating Capacity.

Transparency

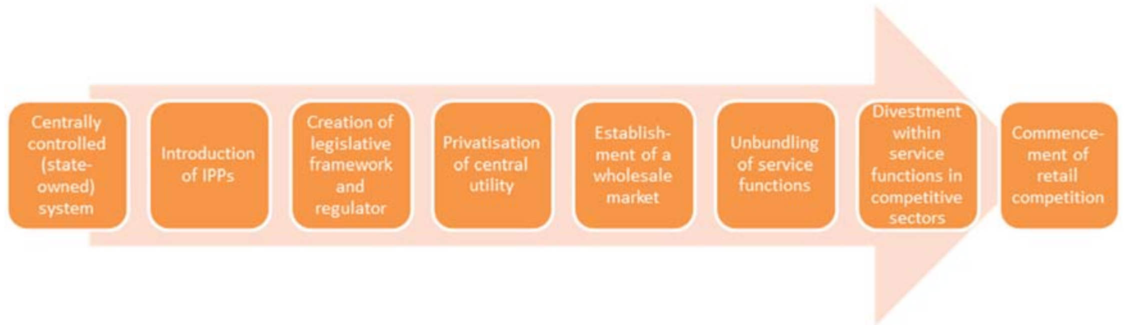
8.8.10 Transparency may help to ease public concerns over the activities of the monopolistic power companies. Published data supporting the calculation of permitted rate-of-return for the companies should answer any questions the public had over it being ‘unfair’.

8.8.11 We see current transparency as adequate. To our understanding, power companies make publicly available extensive information to support their tariff proposals in the Tariff Review, with the exception of forecast data (including fuel costs) on the grounds that this will weaken their bargaining power in future transactions such as the procurements of fuel, tendering of major projects, etc.

ANNEX A: MARKET LIBERALISATION PROCESS

A.1 Non-liberalised electricity markets tend to have a centrally-controlled (state-owned) electricity entity, responsible for the generation, transmission, distribution and supply of electricity, overseen by the Government. The process of liberalising the industry by moving to wholesale generation and retail competition is complex and challenging, requiring several steps as illustrated in Figure 21 below.

Figure 21: Steps in market liberalisation



Source: IPA research.

A.2 Once full liberalisation has been achieved, the generation and supply sectors should be fully competitive, and hence no longer in need of regulation. Transmission and distribution are natural monopolies, requiring price controls to ensure fair value for consumers. For these sectors, cap regulation seems to be the more commonly used form of price setting mechanism, due to the cost efficiency incentives it offers.

A.3 Market liberalisation would be expected to put downward pressure on the price of electricity through competition. Unbundling of generation and transmission facilitates new entry into generation, which intensifies competition and should lead to a decrease in prices. There have been some empirical studies which have attempted to assess the effect of electricity market liberalisation across markets. However, findings have been non-conclusive due to the fundamental differences between markets and issues of cross-country comparability of the data. One study suggested that although "liberalisation and privatisation may reduce electricity prices", the empirical results were "statistically insignificant" [84], whilst another found that the unbundling of generation and the introduction of a wholesale spot market "did not necessarily lower the price and may possibly have resulted in a higher price"[85].

A.4 However, there are many associated challenges and costs to liberalisation. These include, amongst others: [86]

- The cost of setting up and operating an independent system operator (ISO) is substantial, requiring investment in hardware and software, organisational change, and operational systems changes arising from market reforms.

[84] Steiner F (2000): Regulation, Industry Structure and Performance in the Electricity Supply Industry, OECD Economic Studies No. 32, 2001/I
[85] Hattori T, Tsutsui M.: Economic impact of regulatory reforms in the electricity supply industry: a panel data analysis for OECD countries. Energy Policy 2004;32:823-832.
[86] Costs of electricity deregulation: https://ethree.com/papers/Costs_of_elec%20dereg_112204.pdf

- Possible increased prices arising from potential market power abuse and gaming. Where complex market design exists, there is always the potential of abuse by participants in order to extract maximum value out of the market. This is more likely in markets where there is ineffective competition, due to a limited number of participants or the existence of a natural monopoly. Such behaviour can result in increased market prices, as described in Section 2.
- Inefficient investment with stranded costs/assets, as market reforms which aim to introduce subsidies for renewable electricity generation segment can result in stranded costs as non-renewable assets may be under-utilised post reform.

A.5 The past couple of decades have seen the liberalisation of many electricity markets. However, alongside this have been other factors that have influenced electricity prices, including the push for renewables and the decarbonisation of electricity, changing capacity mix as plants have retired and been replaced, and changes in underlying fuel prices. Furthermore, between markets there has been variation in market design, differing levels of complexity and regulation to prevent the abuse of market power and abuse by participants, contrasting policy goals, and different levels of privatisation. These have all contributed to affecting the cost of electricity, making a straightforward comparison of the effect of liberalisation on electricity tariffs extremely difficult to conduct.