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Assunto Revisão dos Regulamentos do Sector Eléctrico

Exmo. Senhor Presidente,

Junto enviamos uma contribuição da REN-Rede Eléctrica Nacional, S.A., para a audição pública relativa à revisão dos regulamentos da competência da ERSE, com os comentários e sugestões de âmbito geral ao "Documento de Discussão", e que nos pareceram mais relevantes.

Incluímos, também, dois trabalhos produzidos pelo consultor NERA (National Economic Research Associates), relativos às Boas Práticas de Regulação Económica e da Determinação do Custo do Capital.

Com os melhores cumprimentos

REN - Rede Eléctrica Nacional, SA
Conselho de Administração

José Penedos
(Presidente)

Anexos: Os referidos.

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Rede Eléctrica Nacional, S.A.

# COMENTÁRIOS

# AO

# "DOCUMENTO DE DISCUSSÃO"

# Revisão dos Regulamentos do Sector Eléctrico

**Lisboa, Março 2001**

## 1. Introdução

O Sector Eléctrico Nacional (SEN), para além de toda a legislação genérica aplicável, encontra-se essencialmente regulado pelo pacote legislativo de 27 de Julho de 1995 que foi parcialmente alterado pelos Decreto-Lei 56/97, de 14 de Março, e 198/2000, de 24 de Agosto (DL's 182/95, 183/95, 184/95, 185/95 e 187/95), e pelo conjunto que rege a Produção em Regime Especial ( 189/88, de 27 de Maio, alterado pelos DL's 186/95, de 27 de Julho, 313/95, de 24 de Novembro, 168/99, de 18 de Maio e 538/99 de 13 de Dezembro). Para além destes, será ainda de referir o Decreto-Lei 338/91, de 10 de Setembro, que rege o funcionamento do Mecanismo de Correcção de Hidraulicidade.

Constituem elementos adicionais de regulação do SEN: os contratos de vinculação entre a produção e o transporte, os contratos de vinculação entre o transporte e a distribuição, o contrato de concessão de serviço público da Rede Nacional de Transporte de Energia Eléctrica (RNT) e ainda a regulamentação emitida, quer pela Direcção Geral de Energia (DGE), quer pela Entidade Reguladora do Sector Eléctrico (ERSE).

Este conjunto normativo do SEN permitiu, e antecipou mesmo, a transposição para o Direito português da Directiva 96/92/CE sobre o Mercado Interno de Electricidade.

A ERSE pretende agora efectuar uma revisão dos regulamentos da sua responsabilidade: Regulamento Tarifário (RT), Regulamento de Relações Comerciais (RRC), Regulamento de Acesso às Redes e às Interligações (RARI) e Regulamento de Despacho (RD). Os primeiros três: RT, RRC e RARI foram publicados em 15 de Setembro de 1998, enquanto o RD data de 15 de Abril de1999.

A ERSE anunciou logo em Maio de 1998, na "Proposta de Regulamentação do Sector Eléctrico" ser sua intenção revê-los durante o ano 2001, o que agora justifica pela necessidade de melhorar a regulação do sector e colmatar algumas lacunas que a experiência de regulação revelou.

Concordamos com a necessidade de revisão urgente de alguns aspectos regulamentares, mas estamos cientes que esta fase terá provavelmente que ser seguida, a curto prazo, por novas revisões na sequência da proposta de directiva da União Europeia sobre o Mercado Interno de Electricidade, cuja aprovação se espera em breve.

## 2. Comentários gerais ao "Documento de Discussão" emitido pela ERSE

O documento da ERSE coloca um leque de questões, a que, pela diversidade e grau de importância respectiva não é possível dar, neste momento, resposta exaustiva.

Pretendemos por isso, neste momento, transmitir à ERSE o que, para a REN, é mais importante na revisão dos regulamentos, que agora se inicia, e que genericamente se pode resumir a:

- Aproximar as práticas de regulação económica das empresas do sector eléctrico nacional das melhores práticas internacionais;
- Adequar os regulamentos ao novo contexto jurídico, económico e financeiro decidido pelo Estado para a concessionária da RNT;
- Adequar as disposições regulamentares, dentro dos limites do actual quadro legislativo, à aceleração da liberalização do sector eléctrico.

## 3. Comentários a algumas questões específicas

### 3.1. Ligação às redes

A preparação da regulamentação do sector, para um contexto mais liberalizado, parece aconselhar que continuem a ser transmitidos aos utilizadores das redes (produtores e consumidores) sinais económicos específicos sobre a adequabilidade do ponto de ligação à rede que pretendem utilizar, sob pena de se assistir a uma degradação da eficiência económica do sistema.

A uniformidade tarifária adoptada no território nacional parece deixar apenas como alternativa de sinal económico a fornecer ao utilizador de rede, o pagamento dos investimentos específicos, incluindo eventuais reforços profundos de rede, implicados pela ligação em causa.

### 3.2. Estrutura tarifária

A estrutura das tarifas, para ser adequada a uma maior aceleração da liberalização do sector, terá de possibilitar, de forma eficaz, o acesso ao SENV de um cada vez mais elevado número de consumidores.

Neste contexto, será pesado e ineficiente, quer sob o ponto de procedimentos comerciais e administrativos, quer sob o ponto de vista de compreensão pelos clientes, continuar a individualizar, junto de cada cliente do SENV, a facturação de cada uma das tarifas de acesso a montante.

Os clientes finais do SEP dispõem de tarifas por nível de tensão, que englobam todos os custos de montante, incluindo a componente de energia e potência. Dentro da mesma lógica, caso venham a optar pela adesão ao SENV, deverão ter tarifas globais de acesso, similares às que dispunham enquanto clientes do SEP, mas descontadas, agora, da componente de energia e potência. É este o procedimento que está a ser adoptado na generalidade dos países Europeus com estádios de liberalização mais avançados.

Importa assim, rever, não só, as estruturas das tarifas de clientes finais do SEP, mas criar novas estruturas paras as tarifas globais de acesso.

### 3.3. Estabilidade tarifária

A experiência já vivida ao longo deste primeiro período regulatório permite evidenciar, pelo menos no que respeita à tarifa de Energia e Potência, a desadequação do mecanismo de correcção com dois anos de atraso, prevista no Regulamento Tarifário. A enorme volatilidade introduzida nos custos de aquisição por factores completamente fora do controlo da REN (principalmente os preços dos combustíveis e as taxas de juro e inflação, relevantes nos Contratos de Aquisição de Energia) coloca dois tipos de problemas:

- Capacidade da REN para absorver na sua dívida oscilações que podem ser da ordem dos 40 milhões contos, cujos custos financeiros e administrativos, de forma alguma, são compensados pela taxa de juro prevista no regulamento e que impõem à empresa uma estrutura de capital incerta e eventualmente indesejável;
- Dificuldade dos consumidores perceberem a necessidade de alterações tarifárias significativas por factos relevantes ocorridos dois anos antes.

Torna-se necessário, não só reduzir o risco financeiro a que a REN está sujeita, mas também delimitar o tipo de desvios que poderão ser objecto do mecanismo de correcção dois anos mais tarde, daqueles que deverão ser antecipadamente objecto de uma Fixação Excepcional de Tarifas.

### 3.4. Aspectos de concorrência no sector eléctrico

#### 3.4.1. Alteração do modelo de relacionamento entre agentes do SEN

A diminuição do nível de elegibilidade terá como consequência a necessidade de existência de um nível intermédio de relacionamento entre os Clientes não Vinculados e a REN (à semelhança do que actualmente acontece com os Clientes Vinculados). Com efeito, a existência de um relacionamento directo entre a REN e um universo potencialmente numeroso de clientes de pequena dimensão obrigaria a duplicar estruturas de apoio comercial (procedimentos de acesso, contratação, contagem, facturação, resolução de conflitos, etc.) gerando acentuadas ineficiências prejudiciais para todo o sistema eléctrico.

Assim, com a eventual excepção dos clientes que se encontram ligados em MAT,

a REN apenas deverá relacionar-se directamente:

- Com as empresas de distribuição para efeitos de liquidação dos serviços de uso da rede de transporte e uso global do sistema, relativos a toda energia saída da RNT e entrada nas redes de distribuição, independentemente desta se destinar a clientes do SEP ou do SENV;
- com produtores e agentes retalhistas (empresas de distribuição vinculada e comercializadores) para liquidação da componente energia e acertos de desvios.

### 3.4.2. Sistema de Ofertas (Gestor de Ofertas)

O RARI no seu Capítulo V – Condições Comerciais de Oferta de Energia Eléctrica e Serviços de Sistema através das Redes e Interligações, conduziu à individualização na organização da REN do Gestor de Ofertas, para promover o relacionamento comercial entre o SEP e o SENV. As principais funções definidas para essa função foram as de organizar um mercado de ofertas, tipo bolsa de energia, e receber a quantificação física dos contratos bilaterais entre os diversos agentes de mercado.

A REN durante o ano de 1999 desenvolveu as acções necessárias para a implementação dessa bolsa de energia, tendo o respectivo sistema informático de recepção de ofertas, encontro de ofertas e facturação da energia ficado concluído no início de 2000.

A REN considera reunidas as condições técnicas para que esta bolsa de energia entre em funcionamento em Portugal, constituindo um relacionamento alternativo à celebração de Contratos Bilaterais Físicos (CBFs). Esta bolsa de energia pode, numa primeira fase, funcionar de modo independente da pool espanhola, com agentes estrangeiros a operar sob a figura do Agente Externo, a fim de aumentar a liquidez desse sistema de ofertas. Deverão igualmente ser previstos mercados intradiários, a fim de permitir aos agentes coordenar e corrigir posições de compra e venda em paralelo com as suas posições no mercado vizinho.

### 3.4.3. Contratos Bilaterais Físicos (CBFs)

De momento, a celebração de CBFs tem constituído a única forma de relacionamento comercial no âmbito do SENV, dada a inexistência do sistema de ofertas. Os CBFs têm também sido a base para o estabelecimento de importações de energia a partir de Espanha, com destino aos clientes não vinculados em Portugal, tal como previsto no Artigo 59º do Regulamento.

A REN considera que este tipo de contratos pode perfeitamente coexistir com o funcionamento em paralelo do sistema de ofertas constituindo um modo alternativo de comercialização de energia que contribui para o fomento da concorrência no sector eléctrico.

De salientar que no país vizinho, apesar de existir uma "pool" na prática mandatória para os produtores de energia, o relacionamento alternativo através de contratos bilaterais físicos é permitido, internamente entre produtores e comercializadores ou clientes qualificados e a partir do exterior através das interligações, entre agentes externos e os mesmos comercializadores e clientes qualificados. Não há, por isso, qualquer razão para proceder de outra forma em Portugal.

A REN, sob a figura do Agente Comercial do SEP, deve poder estabelecer CBFs em paralelo com a possibilidade de colocar ofertas nas bolsas de energia, não havendo razões que justifiquem o procedimento de autorização prévia, que coloca a REN em posição de desvantagem face aos restantes agentes do mercado.

### 3.4.4. Contratos de Curta Duração

A figura dos Contratos de Curta Duração prevista no Artigo 60º do RARI confunde-se com a dos contratos bilaterais físicos, que, em si, já constituem contratos de duração limitada, normalmente a menos de um ano.

Nestas circunstâncias propõe-se a eliminação desta figura do Regulamento, por ser desnecessária.

No mesmo Artigo 60º prevê-se que o Gestor de Ofertas dê conhecimento de ofertas de compra e venda para facilitar a celebração dos contratos de curta duração entre os agentes de mercado. Esta intermediação pelo Gestor de Ofertas é igualmente desnecessária dado os CBFs serem naturalmente negociados entre os agentes de mercado, dentro de algum sigilo comercial.

O que se está a verificar noutros países europeus é uma evolução das bolsas de energia para permitir o funcionamento de um mercado a prazo, tipo físico ou financeiro. Parece no entanto ser cedo para implementar esse mercado a prazo, quando o sistema de ofertas para o dia seguinte ("day ahead market") ainda não entrou em funcionamento e revelou uma liquidez mínima necessária.

### 3.4.5. Declaração Anual de Venda de Energia Eléctrica

Esta figura prevista no Artigo 64º do RARI tem-se revelado de todo desajustada da evolução do sector eléctrico nos últimos tempos, propondo-se a sua eliminação.

Igualmente se propõe pelos mesmos motivos a eliminação da correspondente declaração anual de compra prevista no Artigo 67º do RARI.

### 3.4.6. Condições Comerciais de Acesso às Interligações

No número 4 do Artigo 79º do RARI prevê-se que o Gestor de Ofertas possa colocar ofertas diárias de compra e venda de energia que não foram objecto de contratação no Operador de Mercado Espanhol.

Esta função atribuída ao Gestor de Ofertas confunde as funções de um Operador de Mercado, que deve ser neutro e passivo, com a dos agentes de mercado, que são os agentes comerciais que compram e vendem energia e colocam as ofertas respectivas.

A ideia de uma interligação entre pools está hoje questionada pela necessidade de uma pool independente em Portugal, como passo indispensável ao processo de uma eventual pool ibérica.

Daí que se proponha a eliminação desta atribuição do Gestor de Ofertas prevista no Regulamento.

### 3.4.7. Acerto de Contas

O RARI, no seu Artigo 53º, considera a individualização organizativa — para além do Gestor de Sistema, Gestor de Ofertas, Agente Comercial do SEP, e Transporte de Energia Eléctrica — de uma outra função designada por Acerto de Contas.

As funções definidas para o Acerto de Contas seriam a liquidação das transacções com as entidades com que a REN se relaciona, incluindo a recolha das contagens de energia.

A experiência vivida desde a entrada em vigência dos Regulamentos mostra que existem dois tipos de transacções distintas:

- as transacções de energia dentro do SEP, devidas por um lado aos Contratos de Aquisição de Energia com os Produtores e por outro às vendas da REN à Distribuição;
- as transacções de energia com as entidades do SENV, correspondentes aos acertos de energia e pagamentos das tarifas reguladas de acesso às redes do SEP; a estas transacções adicionar-se-ia a liquidação de energia no sistema de ofertas caso tivesse sido posto em marcha.

As transacções de energia dentro do SEP constituem atribuição do Agente Comercial do SEP por ser dentro da REN o gestor dos contratos em vigor. Todas as transacções com o SENV acima descritas constituem uma atribuição do Gestor de Ofertas, onde o actual Acerto de Contas está de certo modo inserido.

Assim propõe-se a eliminação do Regulamento da função Acerto de Contas com o destaque que lhe está atribuído, dividindo as suas funções pelas figuras do Agente Comercial SEP e Gestor de Ofertas.

### 3.4.8. Contratos de garantia de Abastecimento

O RRC definiu uma figura muito rígida para o estabelecimento pelas entidades do SENV de contratos de garantia de abastecimento (back-up) com a REN.

Até à data de hoje nenhuma entidade a operar no SENV mostrou interesse no estabelecimento de tal contrato.

Por outro lado houve entidades que mostraram interesse em estabelecer com a REN CBFs de muito curto prazo, através dos quais tem sido possível disponibilizar excedentes do SEP para fornecimento dos clientes não vinculados, em alternativa às importações de energia a partir de Espanha.

Assim considera-se que deveria ser possível à REN, sob a figura do Agente Comercial do SEP, estabelecer contratos bilaterais para garantia de abastecimento de entidades a operar no SENV negociados em formas assentes em mecanismos de mercado, ficando a forma actualmente prevista no RRC como uma obrigação de contratação pela REN, no caso de não ter sido possível um acordo comercial com o Agente do SENV que tenha manifestado desejo no estabelecimento de uma garantia de abastecimento.

### 3.4.9. Gestão de Congestionamentos de Redes

As novas versões dos regulamentos deverão possibilitar que a gestão das restrições se efectue através de mecanismos transparentes, eficientes e não discriminatórios, entre os diversos agentes do SEN.

Para que tal se concretize, a solução pode passar pela criação de mecanismos de mercado, diferenciados para diferentes horizontes temporais. Assim, para um horizonte temporal mais largo (semanal ou diário), deverá a futura regulamentação possibilitar a resolução de restrições de rede através da realização de leilões da capacidade disponível pelos agentes interessados em a explorar. As receitas que decorreriam destes leilões, poderiam ser utilizadas no reforço da RNT, tendo em vista a futura eliminação da restrição, bem como para compensar o desfazer de negócios que tivessem de ocorrer em tempo real (re--despacho), perante restrições de rede que não tivessem sido inicialmente previstas.

O modelo proposto tem como principais vantagens o facto de apresentar um sinal económico forte aos agentes e o de ser um incentivo financeiro à eliminação das restrições de rede, sendo de realçar que este modelo somente se traduziria num aumento dos custos para os agentes que interviessem na restrição de rede existente. Pensamos ainda que o modelo sugerido proporcionaria uma repartição da capacidade disponível entre CBF's, ofertas "spot" e SEP de uma forma transparente e não discriminatória.

O modelo apresentado (leilões para horizontes temporais superiores ao tempo real) implicará uma remodelação do Artigo 41º do RARI, atendendo a que deixará de fazer sentido um agente ser indemnizado em virtude da existência de restrições de rede, a menos que essa restrição surja após um vinculo do Gestor de Sistema a esse contrato, i.e., após a validação técnica por si efectuada.

Pensamos que a metodologia proposta obrigará também a uma remodelação regulamentar mais ampla, nomeadamente no seu enquadramento nas funções do Gestor de Sistema, bem como no registo e divulgação de informação.

### 3.4.10. Serviços de Sistema

Prevendo-se a entrada em serviço de um novo PNV, de grande dimensão, no decurso do novo período regulatório, torna-se necessário enquadrar a sua actuação, bem como a dos PNV actualmente existentes, quanto ao fornecimento de serviços de sistema.

Em especial no que respeita ao serviço de reserva, deverão ser estabelecidas as formas de relacionamento comercial possíveis — contratos bilaterais e/ou ofertas "spot" — por forma a obter, também neste domínio, uma partilha de benefícios na gestão dos desvios de regulação.

No entanto, o serviço de reserva — tal como hoje é entendido e posto em prática em sistemas com outro grau de liberalização — não se encontra previsto nos actuais regulamentos, os quais estabelecem definições dos serviços de sistema muito decalcadas dos Contratos de Aquisição de Energia em vigor no SEP. Como consequência, torna-se necessária uma modificação da definição de serviços de sistema.

A determinação dos preços de desvio deverá decorrer da forma como for implantado o relacionamento comercial neste âmbito.

### 3.4.11. Política de Gestão do Ambiente

A REN está de acordo com o facto da ERSE considerar que as preocupações ambientais de índole empresarial devem ser estimuladas no âmbito de mais um contributo para o tão ambicionado desenvolvimento sustentável do país.

## 3.5. Os Modelos de Regulação Económica

É certo que poderá haver nesta fase de revisão dos regulamentos um repensar dos modelos regulatórios das empresas envolvidas. Contudo, pensamos ser matéria sobre a qual terá de se agir com grande prudência, já que um enquadramento regulatório que sugira evidência de não recuperação de custos incorridos de "forma prudente" pelas empresas, em que naturalmente se inclui o custo do capital, poderá, no ambiente mais liberalizado que se aproxima, provocar, a prazo, a disrupção do sector.

A este propósito gostaríamos de pôr à consideração da ERSE o documento "The Principles of Good Monopoly Regulation", que juntamos em anexo, documento que foi elaborado pela NERA, actual consultor da REN.

## 3.6. Custo do Capital

Na aplicação de qualquer método de regulação, o regulador tem de garantir que o nível de proveitos que vai permitir (nomeadamente com o estabelecimento de preços, ou de uma taxa de rendibilidade máxima) proporciona um retorno justo para o capital sob pena de deixar as empresas reguladas incapazes de financiar as suas actividades.

### 3.6.1. A Prática da Regulação e o Custo do Capital

A determinação da taxa de rendibilidade permitida pelo regulador, com base no método puro de Averch – Johnson ou qualquer das suas variantes, exige sempre a avaliação prévia do custo médio do capital da empresa regulada.

As dificuldades no cálculo do Custo Médio Ponderado do Capital (CMPC) derivam da prática regulatória específica e, também, da controvérsia à volta do tema, apesar dos avanços significativos da teoria financeira, com a consequente dificuldade em indicar qual o melhor caminho do ponto de vista metodológico.

Qualquer empresa, operando em mercado concorrencial, estabelece os seus preços no mercado dos produtos tendo presente elementos que, na maioria das situações, são independentes das decisões relativas à sua estrutura financeira e à taxa de remuneração do capital alheio e do capital próprio.

Uma empresa regulada, pelo seu lado, estabelece os seus preços e tarifas com base em procedimentos regulatórios (regulamentos) os quais, sobretudo no caso de métodos de regulação do tipo "custo do serviço", tem explicitamente presente os aspectos relativos à estrutura financeira e ao custo do capital.

Assim, os efeitos dos procedimentos regulatórios sobre o custo do capital são de importância considerável para os investidores, consumidores e decisores. Quando se verifica, de forma "instantânea", uma significativa alteração na estrutura financeira da empresa regulada, mesmo que resultante de actuação não imputável ao regulador, este não pode ser indiferente a tal facto, dado o impacte que tem nas decisões intertemporais da empresa.

### 3.6.1. A Determinação do Custo do Capital

A utilização das abordagens financeiras tradicionais na determinação do custo do capital está suficientemente descrita na literatura e tem, no caso das empresas reguladas, privilegiado em geral o Modelo de Equilíbrio de Activos Financeiros ("Capital Asset Pricing Model").

A unificação que é possível fazer, dados os pressupostos comuns de mercados de capitais perfeitos, entre as abordagens tradicionais aos problemas de determinação de rendibilidade de equilíbrio de activos financeiros ou activos reais levam a que seja possível deduzir o custo do capital próprio através da interacção entre o Modelo de Equilíbrio de Activos Financeiros, a abordagem de Modigliani-Miller da Estrutura de Capital e os Modelos de Avaliação de Activos Contingentes.

As duas primeiras abordagens não têm em conta, na sua formulação teórica básica, os efeitos das acções tomadas por qualquer entidade reguladora ou seja pelo processo de regulação, sobre o valor da empresa e, portanto, sobre o custo do capital. Ambos os métodos consideram, de certa forma, que o mercado tem um poder "místico", no sentido que avalia os factores mais relevantes na determinação das rendibilidades de equilíbrio.

Assim, pode utilizar-se como alternativa conceptualmente interessante, (apesar de mais pesada na informação necessária) um método que tem em conta, pelo menos de forma aproximada, os efeitos do processo regulatório e a forma como afecta o custo do capital de uma empresa regulada.

O trabalho pioneiro é o de Brennan – Schwartz, o qual permite analisar os efeitos dinâmicos da regulação sobre o valor de mercado da empresa. Esta abordagem é conduzida tendo por base os modelos de avaliação de activos contingentes.

Qualquer que seja o método utilizado, no entanto, ele exige a determinação da constante de volatilidade a qual depende, entre outros factores, da taxa de crescimento da empresa e da sua variabilidade o que pode levar a questionar o seu cálculo baseado em dados históricos e a dificuldades diferenciadas consoante a abordagem utilizada. O $\beta$ não é, então, um parâmetro fixo da empresa.

### 3.6.2. O Custo do Capital e a Taxa de Rendibilidade Permitida

Para determinação da taxa de rendibilidade permitida, a questão fundamental é a da escolha do melhor modelo a utilizar no cálculo de custo do capital. A Teoria Financeira e a Teoria da Regulação Económica não permitem, no estado actual do conhecimento, uma resposta única. Possivelmente, a melhor resposta será a de que o melhor modelo é o que permite um cálculo mais adequado e rigoroso da "verdadeira" taxa de rendibilidade **justa** da empresa regulada.

Todos os modelos teóricos de determinação do custo do capital, quando aplicados a dados reais, produzem taxas de rendibilidade que estão sujeitas a erros que podem ser significativos. Os modelos tenderão a ter, também, diferentes níveis de desempenho consoante os diferentes cenários económicos em que são aplicados.

### 3.6.3. O Cálculo do Custo do Capital na Prática

Na determinação do risco associado ao capital próprio, uma das dificuldades mais frequentes ocorre quando as empresas não são cotadas. Nestas situações, uma forma usual para o calcular é através da comparação dos $\beta$ das actividades das empresas estrangeiras similares, havendo de ter em conta a dependência do seu valor das diferentes estruturas financeiras das empresas. Existe ainda dificuldade de incluir, no cálculo do $\beta$, alguns factores de risco da actividade da empresa (evolução dos preços dos combustíveis e repercussão dos custos nas tarifas) e a própria tendência evolutiva do $\beta$ ao longo do período de regulação (assistimos a um aumento do seu valor no final do período regulatório). Alguns destes factores poderão justificar um aumento de $\beta$ posterior à obtenção da sua estimativa analítica inicial.

Assim, considera-se que em ambiente de regulação económica, se devem considerar outros factores de risco sistemático não captados pelo $\beta$, e que afectam a taxa de rendibilidade de equilíbrio. Dois factores relevantes são os que têm a ver com a rendibilidade dos dividendos e com o enviesamento devido ao processo de regulação económica. O custo do capital próprio deve então ter em conta, aqueles dois aspectos, sendo a questão do enviesamento particularmente importante dado que os resultados futuros da empresa são restringidos, de forma activa, pelo processo regulatório.

A não consideração daqueles determinantes pode levar a estimativas subavaliadas do custo do capital próprio, sobretudo no caso de os efeitos de enviesamento serem relevantes.

Ainda neste âmbito, devemos acrescentar que se os reguladores fixarem os proveitos iguais aos níveis de custos eficientes incluindo o CMPC correspondente à estimativa média para as taxas de rendibilidade do mercado não estão a encorajar investimentos eficientes, porque no mercado, as empresas eficientes têm um custo do capital superior ao valor médio do mercado e se a ERSE não tiver em consideração este aspecto, as empresas reguladas, particularmente no contexto da maior liberalização que se avizinha, terão dificuldades de financiamentos e sentir-se-ão incapazes de manter os níveis de qualidade e eficiência mais adequados aos consumidores.

Considera-se imprescindível que o Regulamento Tarifário venha a estabelecer, não só os princípios metodológicos para o seu cálculo, como a relação entre o CMPC e os parâmetros de remuneração de activos explicitamente considerados nalgumas fórmulas tarifárias.

### 3.6.4.O Cálculo do Custo do Capital. Conclusão

No entender da REN é urgente a revisão do custo do capital, não só em face da alteração de circunstâncias ocorridas na estrutura de capital da REN, mas também por existirem dúvidas quanto à sua determinação nomeadamente no efeito fiscal sobre a remuneração do capital próprio e no processo do tratamento das comparticipações ao investimento. Assim tudo indica que o CMPC tenha sido determinado para uma estrutura de financiamento do activo não descontada de comparticipações, que parece aplicar depois a uma base de activos, líquidos de comparticipações.

Relativamente ao cálculo do custo do capital, gostaríamos, também de colocar à consideração da ERSE, o documento "Estimation of REN's Cost of Capital, A Report for REN", preparado pela NERA.

## 3.7. Alguns Aspectos Financeiros da Regulação da REN

Para além da volatilidade financeira, já acima referida, que o actual modelo regulatório está a impor à REN, a falta de sincronismo entre os prazos de pagamento, impostos pelos Contratos de Aquisição de Energia, e os prazos de recebimento previstos no Regulamento de Relações Comerciais está a provocar dificuldades de tesouraria, obrigando a recorrer a financiamentos de curto-prazo de custo elevado.

Urge corrigir esta situação, tanto mais que o Regulamento Tarifário, não prevê a remuneração do fundo maneio que a REN tem tido de usar para fazer face àquele dessincronismo.

# ANEXO I

# THE PRINCIPLES

# OF

# GOOD MONOPOLY REGULATION

# THE PRINCIPLES OF GOOD MONOPOLY REGULATION

**Prepared by NERA**

23 February 2001
London

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# 1. INTRODUCTION

This report sets down the economic principles of natural monopoly regulation. The principles it describes are derived from academic and regulatory sources from around the world, and are universally applicable, but I have attempted to express them in terms relevant to any European country.

For this reason, I have not relied on the standard phrases of US regulation, such as the need to offer a "reasonable rate of return". In the US, the meaning of such phrases has been clarified by a number of legal cases, of which European commentators are often unaware. Consequently, in the UK and in other European countries, I have encountered regulators, academics and industry staff who place their own interpretation on such phrases. These interpretations are often misleading. However, instead of trying to correct such misunderstandings directly, I have tried to express the economic principles of natural monopoly regulation in new, simple terms that do not carry the "excess baggage" of prior interpretation. In doing so, I am conscious that some phrases may be unfamiliar, but in each case I am confident that my conclusions are hard to contradict.

For instance, I have proposed that all regulators should offer investors a "reasonable prospect of cost recovery". Many regulatory laws contain no reference to such a principle. However, it is impossible to imagine, or to advocate, a regulatory system that expressly tries to deny investors a reasonable prospect of cost recovery. This then is the ultimate test: if you cannot see a principle that I espouse encapsulated in your own regulatory regime, try to imagine a system that had rejected it. In every case, you will see that such regulatory regime was bound to fail.

## 1.1. Summary of Conclusions

In a European context, any discussion of natural monopoly regulation quickly encounters a dispute between too polar extremes: cost pass-through and "price cap regulation". In the former approach, revenues equal the company's actual costs (including the cost of capital). The latter approach sets revenues different from actual costs (by some unspecified method), so that regulated companies have an incentive to cut costs. The aim of this report is to explain that neither of these extremes is workable, and that all regulation is a compromise between cost pass through and incentive regulation. I summarise this compromise as the need for regulators to offer a reasonable prospect (but not a guarantee) of cost recovery.

The basis for this conclusion is an examination of the economic conditions of natural monopolies, meaning long-lived, irreversible investments in facilities that serve large numbers of customers. This report has been written with electricity networks in mind, but the principles set out in it apply to any such natural monopoly.

In such industries, regulation must succeed in encouraging investors to commit funds to long-term investment, when other sectors offer attractive opportunities whose return is not so dependent on the decisions of government officials. Regulators must therefore play their role in helping the industry compete for funds in capital markets. Otherwise, customers will not receive the quantity or quality of service that they want.

To encourage investment, regulators need to avoid setting revenues in ways that put cost recovery in doubt. This constraint imposes a limit both on the *minimum level* of allowed revenues, and on the *methods* used to set it. Investors want to know that revenues will cover costs now and in the future. Such assurance will not be available to investors, if regulators adopt subjective methods that make future revenues a matter of pure guesswork.

Overall, therefore, any regime for regulating natural monopolies must adopt *stable and predictable* regulatory methods that offer a *reasonable prospect of cost recovery*, such that the regulated companies can *attract capital*. These are universal economic principles of regulation.

## 1.2. Outline of this Report

The rest of this report has the following pattern. Section 2 examines the economics of regulation - what regulation is trying to achieve, and what that means for a good regulatory system. Section 3 recognises explicitly that individual regulators always face one-sided pressure to cut prices and discusses the constraints that prevent such "opportunistic" price cuts from being good regulatory policy.

Section 4 applies the basic principles to the choice of regulatory method, in the context of price caps. (In this section, I refer to price caps as a general term for any form of "incentive regulation", in which the company can increase its profits by becoming more efficient.) Section 5 discusses briefly the role that regulatory procedures play in ensuring that only the best methods are adopted.

In recent times, regulators have placed great emphasis on the use of "benchmarking" to set revenue allowances, as an alternative to using information on a company's actual costs. This process is deeply flawed (and has not, in practice, provided any real alternative to setting revenues equal to actual costs). However, recent publications by ERSE list benchmarking as a possible approach. An appendix to this report therefore explains why regulatory benchmarking is a flawed technique.

# 2. ECONOMICS OF REGULATION

In this section, I set out why economic regulation of some firms is necessary and, hence, what it is intended to achieve.

## 2.1. Why Is Regulation Necessary?

The primary method of organising private sector activity is through the operation of a market. Provided that certain basic rules are defined (principally, who owns what resources), markets allow producers to compete against one another, unfettered by any constraint other than the conditions of supply and demand. If these conditions meet certain criteria, competition will produce the best outcome. However, if these criteria are not met, competition produces undesirable outcomes.

For example, in cases of monopoly, competition is not feasible and a profit-maximising monopoly will raise its prices above its costs, to increase its profit. High prices do not only allow the firm to earn profits that are higher than they need to be. High prices also discourage demand that could be met at a cost that consumers are willing to pay. Both factors result in a loss of potential benefits to society and provide governments with a reason to intervene in the operation of the market.

Monopolies are maintained by barriers that prevent other companies from entering the market when they would otherwise find it profitable to do so. Some "entry barriers" can be eliminated - for instance, it is possible to abolish legal constraints on who is allowed to enter a market. However, some monopolies exist because of the intrinsic economic conditions of production. These monopolies are called "natural monopolies" and require permanent regulation of their behaviour, if the undesirable effects of monopoly are to be avoided. The primary characteristic of a natural monopoly is that:

- The industry experiences large economies of scale (relative to the size of the market), such that one firm meeting total demand is always cheaper than the total cost of two or more firms, each meeting a share of total demand.

In such conditions, continuing competition in the market is either inefficient or impossible. Most network utilities experience large economies of scale, either in their business as a whole, or in an individual service, or in providing a service in each location.

Economies of scale do not rule out competition entirely. Consumers can still hold competitions to select the cheapest provider of a service, from among several potential providers. This form of competition is sometimes known as "contestability" or "competition *for* the market" (as opposed to "competition *in* the market"). However, most network utilities experience additional conditions that prevent such competition for the market from taking place. These conditions (which are sometimes classed as additional conditions of a natural monopoly) are:

- the industry invests in assets that have very long lives;
- these investments are irreversible (ie the assets cannot be withdrawn from the industry without substantial cost or loss of value);
- the level of demand needed to capture economies of scale covers sales to a large number of customers; and
- customers would incur a substantial "transactions cost" if they wished jointly to negotiate a contract with a single supplier.

In an industry with long-lived assets, consumers would need to sign a long-term contract with the provider, in order to capture the benefits of "competition for the market". To capture the necessary economies of scale, a group of consumers would need to join together in a "coalition" and to negotiate as a body. For utility networks, the cost of building a coalition of customers makes the necessary negotiations impossible (or at least prohibitively expensive).[1]

In these conditions, competition is inefficient and undesirable. Consequently, competition is not a useful role model for the appropriate form of interventions by government. Instead, in conditions of natural monopoly, it is more useful to design such interventions as a proxy for the long-term contract that consumers would want to negotiate. The role of a sector-specific regulator is to negotiate the terms of service on behalf of consumers, and to update those terms if conditions change in unforeseen ways. How the regulator conducts these negotiations defines a regulatory regime.

## 2.2. What Is Regulation Intended to Achieve?

Profit-maximising monopolies restrict the supply of a product or service in order to drive up the price and to raise their profits. The starting point for regulation is simply the desire to increase output and to bring prices back down towards the level of costs, including the costs of capital.[2] The main terms of monopoly regulation are:

1. Legal protection of a monopoly in return for an obligation to meet all reasonable demands for the service:

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1 In the NERA report for the Dutch Ministry of Economic Affairs on "Specific Competition Rules for Network Utilities" (March 2000), we listed the conditions that made sector-specific regulation necessary. These conditions included those of natural monopoly, ie: economies of scale/scope, long-lived assets and sunk costs, and customers' inability to capture the economies of scale and scope (transactions costs). We also referred to other criteria (switching costs, frequency of repeated cases and distributional concerns) that might make sector-specific regulation necessary even for markets that do not exhibit natural monopoly conditions.

2 Regulatory economists divide the accounting profits of a regulated company into two parts: the cost of capital, or the rate of return required to reimburse investors, sometimes known as the "normal profit"; and any rent or "supernormal profit" earned above the cost of capital. Unless stated otherwise, when I use the term "costs", I am referring to the economic definition of costs, which includes the cost of capital or a "normal profit".

2. a promise that the company will recover its costs, balanced by a restriction on revenues or prices that prevents the company from earning monopoly profits; and

3. A set of minimum quality standards that prevents the company from profiting by reducing the quality of service (as a substitute for raising prices).

The effect of these instruments is to offset the tendency for monopolists to restrict supply and to raise prices. In economic terms, I would describe price reductions as a move towards "allocative efficiency", ie a desire to encourage efficient choices by consumers, which can be achieved by signalling the cost of products and services in their prices.

An unrestricted privately owned monopoly usually has an incentive to minimise costs, in order to maximise profits.[3] Any regulatory device that links prices to costs will change the incentives facing the monopolist. In general, linking prices to costs reduces the incentive for the firm to minimise costs. Unnecessary escalation of costs would be undesirable, so monopoly regulation is also driven by a concern for cost minimisation, or "productive efficiency".

Maximising economic efficiency will maximise benefits to society. In some monopoly industries, a reduction in prices will only bring about a small increase in demand, and hence a small increase in allocative efficiency. Nevertheless, regulators may be given the power to restrict prices, with the aim of curbing monopoly profits. Prices would still be set equal to costs (as required for allocative efficiency), but the reason for doing so would be the desire to eliminate unnecessary monopoly profits (in excess of the cost of capital). In such cases, the curbs on monopoly profit reflect the regulator's aim of maximising *benefits to consumers*, rather than efficiency or benefits to society as a whole, including shareholders.[4] Such aims are consistent with the model of regulation as a proxy for negotiations by consumers.

In practice, maximising benefits to consumers also requires the pursuit of economic efficiency, with the result that the potential for conflict between efficiency and consumer benefits is limited. In summary, regulation intended to maximise benefits to consumers must ensure (1) that production is efficient and (2) that prices reflect total costs, including the cost of capital.

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3 This condition does not hold universally. A monopoly fearful of potential competitors may overinvest, thereby raising total costs but making it easier to survive a price war, in order to deter others from entering the market. However, such behaviour is a reaction to particular market conditions. Private sector monopolies do not have an inherent tendency to overspend in the absence of regulatory interventions or threats.

4 In economic terms, consumer benefits are known as the "consumer surplus", whereas benefits to society are known as "welfare". See Schmalensee, *Good Regulatory Regimes* (RAND Journal of Economics, Vol 20 No 3, Autumn 1989) for a study of the effect of choosing one or other objective.

## 2.3. How Does Regulation Encourage Efficiency?

Regulation of privately owned monopolies uses the profit motive to achieve both productive efficiency and allocative efficiency, but there is inevitably a trade-off between these two aims.

In their seminal work on regulatory economics,[5] Laffont and Tirole set out the simple model of monopoly regulation. In this model the firm's total revenue[6] set by R=a+(1-**b**)*C. This revenue formula allows a monopoly to:

- recover its costs (C) which includes the cost of capital or normal profit;
- to receive an incentive payment consisting of a fixed payment (a) less a variable payment dependent on costs (**b** times C), so that the total incentive payment increases when costs fall.

The incentive payment provides a reward for cutting costs below a target level. The parameter **b** determines the power of the incentive to cut costs.

If **b** is equal to 0, the formula reduces to R=a+C. In such conditions, the firm has no incentive to minimise costs, since it can pass through all costs, C. However, setting **a** equal to zero means that prices always reflect costs, which is *allocatively efficient.*

If **b** is equal to 1, the formula reduces to R=a. In this case, the revenue is fixed, which gives a profit-maximising firm a powerful incentive to increase profits by reducing costs. Such behaviour enhances *productive efficiency*. However, actual costs are unlikely to equal **a** exactly, so this boost to productive efficiency is achieved only by sacrificing allocative efficiency.

All regulation relies on the profit motive to drive the behaviour of privately owned regulated firms. Hence, incentive regulation is any form of regulation in which **b** is greater than zero, in which case privately owned companies can increase profits by reducing costs.

In summary, regulators encourage *productive efficiency* by allowing regulated companies to earn a revenue higher than their costs (ie to increase profits), when they cut costs below a reasonable target. Regulators achieve *allocative efficiency* by keeping revenues close to costs. All regulation involves a trade-off between these two economic objectives.

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5 J.J.Laffont and J.Tirole, *A Theory of Incentives in Procurement and Regulation*, MIT Press, 1993, p69

6 A similar formulation is found in Vickers, Armstrong and Cowan, where the regulatory formula is defined as an average price cap, P, set by relation to average costs *per unit*, c. They therefore use the formula P = **a** + (1-**b**).c. This formulation describes a price cap, rather than a revenue cap. It means that allowed revenue rises in proportion to demand, but otherwise its incentive properties are the same. See M.Armstrong, S.Cowan and J Vickers, *Regulatory Reform, Economic Analysis and British Experience*, MIT Press, 1994, p40.

## 2.4. What is the Best Form of Regulation?

Around the world, a large amount of literature from academics and regulators claims that price caps are inherently superior to "cost of service regulation" or "rate of return regulation". In such literature, price caps are contrasted with regulatory schemes in which a monopoly is allowed to pass through its actual costs, including a "guaranteed" rate of return. In practice, as the following sections show, few if any regulatory schemes guarantee cost pass-through or a particular rate of return. Consequently, price caps play a role in clarifying incentives, but do not represent a whole regulatory system distinguishable from others. Every regulatory system offers a balance between incentives and cost pass-through.

### 2.4.1. Practical definitions of different forms of regulation

#### 2.4.1.1. *Cost of Service Regulation*

Cost pass-through ("Cost of Service" or COS regulation) prevents a company from earning a monopoly profit and is allocatively efficient. However, in its pure form, COS regulation provides no incentive for productive efficiency in the form of cost minimisation.[7] In 1962, Averch-Johnson[8] pointed out that cost pass-through leads to over-investment (compared with a theoretical optimum), because firms earn a return on all additional investment. "Firms have an incentive to expand their capital base so as to achieve a greater absolute profit whilst staying within the constraint on their profit rate."[9]

For these reasons, regulators are generally reluctant to allow monopolies to include all their costs *automatically* in their prices and, in practice, few regulators have ever allowed automatic pass-through of costs. First, costs are subject to a series of tests, eg, (in the US) to ensure that costs were "prudently incurred", or that investments remain "used and useful". Secondly, even in COS regulation, regulators fix tariffs at reviews and then leave them unmodified for some time, until either the regulator or the regulated company prompts the next review. In between reviews, the fixed tariffs allow the company to increase profits by reducing costs – a phenomenon known as "regulatory lag".[10] Bonbright defines this term as "the *quite usual* delay between the time when reported rates of profit are above or below standard and the time when an offsetting rate decrease or increase may be put into effect by commission order or otherwise". [11]

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7 Cost pass-through may enhance efficiency if the incentive to spend overcomes the monopolist's desire to restrict output as a means of holding up prices.

8 Averch, H and Johnson, L. (1962): "Behaviour of the Firm under Regulatory Constraint", American Economic Review, 52, No 5, December 1962, p 1052-1063.

9 Vickers and Yarrow, *Privatisation: An Economic Analysis*, 1988, p82

10 See Laffont and Tirole, p15.

11 Bonbright, J C, Danielsen, A L, and Kamerschen D R, *Principles of Public Utility Rates*, Public Utilities Reports, Inc, Arlington, VA, 1988, p96. Bonbright also refers to "regulatory lag" on pages 198, 307, 350, 358, 363 and 574.

Hence, in practice, even COS regulation provides some incentive for productive efficiency (i.e. cost minimisation).

#### 2.4.1.2. *Price Cap Regulation*

At the other extreme, price cap ("PC") regulation provides a powerful short-term incentive for productive efficiency. The price cap sets allowed revenues that are independent of (exogenous to) unit costs. A private company will therefore make more profit by cutting its costs. However, such a price cap is unlikely to track movements in unit costs very accurately. Any sustained difference between price caps and unit costs reduces allocative efficiency and creates additional problems for the regulator and/or the regulated company. "Too high a price ceiling makes the firm an unregulated monopolist, too low a cap conflicts with [financial] viability."[12] Eventually, even price caps must be reset to bring them closer in line with costs.

Hence, COS regulation provides short-term incentives through "regulatory lag", whilst PC regulation links prices to costs at regulatory reviews. As Laffont and Tirole note:[13]

> "...it would be simpleminded to make a strong distinction between COS and PC regulations on the basis that one is very low powered and the other very high powered. After all in both regimes prices are set by the regulator for some length of time."

### 2.4.2. The optimal degree of cost-sharing

Given the similarity between price caps and cost of service regulation, a common question under both systems is the extent to which revenues should be tied to costs, as opposed to fixed independently. Armstrong, Cowan and Vickers [14] suggest that the desire to revise price caps in the light of movements in actual costs springs from (1) distributional concerns (prevention of monopoly profit), (2) allocative efficiency and (3) risk aversion on the part of the company (ie unwillingness to make risky investments out of a fixed income). All these factors mean that some compromise between automatic cost pass-through and pure price cap is optimal.

This finding is reinforced by the work of Schmalensee,[15] who analysed the effects of different forms of regulation in a world characterised by uncertainty over future costs. Whether aiming to maximise social welfare or consumer benefits, Schmalensee found that a pure price cap was rarely optimal. When he assumed that the aim of regulation was to maximise

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12 Laffont and Tirole, p17.

13 Laffont and Tirole, p18.

14 M.Armstrong, S.Cowan and J Vickers, *Regulatory Reform, Economic Analysis and British Experience*, MIT Press, 1994, p40ff.

15 R. Schmalensee, *Good Regulatory Regimes*, RAND Journal of Economics, Vol 20 No 3 Autumn 1989, pp 417-436.

consumer benefits subject to the need to give investors a non-negative expected profit overall, Schmalensee found that the cost sharing (pass-through) ratio of 40% to 60% proved to be optimal in the most conditions.[16]

### 2.4.3. The respective roles of price caps and revenues based on actual costs

Price caps can play a role in defining maximum allowed revenues for several years at a time. During this period, price caps provide short-term incentives for cost minimisation. However, over the long-run, it is optimal for regulators to bring prices into line with actual costs. This aim can be achieved either by resetting the price cap at each regulatory review, or by including automatic adjustments within the revenue formula. As long as either procedure is predictable, they can achieve the same effects.

## 2.5. Do Price Caps Encourage Efficient Long-Term Investment?

Simple models of a price cap assume that costs and revenues are all contained within one period. However, one of the characteristics of natural monopoly that makes regulation necessary is the importance of long-lived investments. Any regulator needs to overcome the desire of monopolists to restrict supply, in order to achieve productive efficiency. In the case of network utilities, a regulatory regime must encourage long-term investment to expand supply. It is not clear how a price cap, which encourages short-term cost minimisation, will provide the necessary incentive.

Newbery poses the problem and the answer as follows:[17]

> "What would be needed to persuade investors to sink their money into an asset that cannot be moved and that may not pay for itself for many years? The investors would have to be confident that they had secure title to future returns and that the returns would be sufficiently attractive."

As noted above, Armstrong, Cowan and Vickers identified a number of factors that would lead to price caps being reviewed and reset. Such reviews, even if they happened every 5 years, would occur around 10 times during the life of a typical electricity network asset. In order to assess whether or not they had "secure title to future returns", investors would need to know at least in principle, how each of these reviews would be conducted, and on what basis the price cap would be reset.

16 The 40% to 60% range (ie $0.4<b<0.6$) turned out to be optimal in the most conditions – 283 out of 625 different simulations. The 20% to 40% range ($0.6<b<0.8$, ie less pass-through of costs) was optimal in 231 out of 625 conditions, with other ranges proving optimal in substantially fewer sets of conditions. Neither pure price cap nor pure cost pass-through proved optimal in any conditions. See also Brian Williamson (1997), "Incentives and commitment in RPI-X regulation", *NERA Topic*, No. 20 on the optimal degree of cost sharing.

17 D.M. Newbery, *Privatization, Restructuring and Regulation of Network Utilities*, MIT Press, 2000, p29.

In considering the incentive effects of "price cap regulation", it is therefore important not to focus solely on the incentive properties of a single price cap formula, but on the long-term prospects for revenues offered by the long-term process of setting and revising price cap formulae. In order to offer incentives for efficient long-term investment, individual regulators must be able to offer investors a reasonable prospect that they will be able to recover all the costs of their investment.

By a "reasonable" prospect, I mean here a regulatory commitment to allow cost recovery that is both predictable (so that investors can understand what the regulator is offering) and credible (so that investors believe the regulator). How regulators can contribute to, or undermine, the predictability and credibility of a regulatory regime is discussed in section 3.

## 2.6. Implications for Regulatory Decisions

### 2.6.1. Academic opinion

Academic opinion seems to be united in finding that pure price caps, set once and left untouched indefinitely, are unlikely to meet the aims of regulation. For a variety of reasons, price caps should be reset at some point closer to the level of actual costs in the company concerned. In this respect, Price Cap regulation does not differ from other forms of regulation, including Cost of Service regulation and cost-sharing.

### 2.6.2. Practical experience

This academic finding is backed up by close examination of actual regulatory decisions. Price caps have now been in operation in the US and the UK for over 10 years. At various points, these price caps have been re-set and the process of resetting the price cap has been constrained by the need or desire to keep prices in line with actual costs.

A good illustration of this process is provided by the US history of price caps for regulation of telecommunications. The industry is characterised by asset lives of only 10 to 20 years, and the gradual reduction of economies of scale has allowed competition to enter many parts of the system. One might expect price caps to reflect a "market" or "pseudo-competitive" price, but in fact the starting point for such price caps is the regulated firm's own costs.

The need to review price caps when prices and costs move out of line is well illustrated by the comments of Commissioner Knight (of the California Public Utilities Commission) when setting a price cap for telephone companies GTE California and Pacific Bell in 1998.[18]

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[18] The following quotations are extracted from the Draft Decision of Commissioner Knight, *Rulemaking on the Commission's Own Motion into the Third Triennial Review of the Regulatory Framework Adopted in Decision 89-10-031 for GTE California Incorporated and Pacific Bell,* Rulemaking 98-03-040, Filed 26 March 1998, pp 49-50..

> "In deciding to suspend the cost-sharing rules in favour of a fixed price cap, Commissioner Knight noted that the companies might be obliged by their duty to shareholders to apply for a revision to prices if their rate of return fell too low."

In other words, imposing a price cap widens the permissible variation in the rate of return, in order to strengthen incentives for cost minimisation. Price caps do not, and are not expected to, eliminate the need to keep prices in line with actual costs, or to keep rates of return within acceptable bounds.

### 2.6.3. Conclusion

It is widely acknowledged that price caps are not permanent instruments, but will be revised in the light of unforeseen changes in costs and other conditions. In practice, therefore, the incentives provided by any regulatory formula depend on how costs (and cost savings) are shared both *at* and *between* reviews.

In the context of long-term investment, the incentives for efficiency depend also on investors' perception of future regulatory reviews, and whether they will offer a reasonable prospect of cost recovery over the whole life of the asset.

Both the need to recognise costs, and the need to provide efficient long-term incentives, help to define how a regulator should carry out any individual price cap review.

# 3. CONSTRAINTS ON REGULATION

When a regulator is setting (or re-setting) revenues or tariffs, his or her decisions are subject to a number of constraints. These constraints cannot be circumvented and limit the regulator's discretion over the level and form of revenue controls, including price caps. In this section, I explain the main constraints on regulators. Together with the economics of regulation (as set out in section **Error! Reference source not found.**), these constraints define the key principles of regulation.

## 3.1. What Information Does the Regulator Have?

Modern theories of regulation recognise the factor known as "asymmetry of information", ie that regulated firms possess information that the regulator does not. In particular, regulated firms know more about their potential to reduce costs than regulators. Regulators can observe the actual costs that derive from current behaviour, but they can never know what "efficient costs" would be under efficient behaviour. Regulators can collect information in order to narrow the gap of understanding, but they can never possess information as good as that available to the company. This constraint on regulation is well described by Vickers and Yarrow:[19]

> "If a regulatory agency had as much knowledge about industry conditions and behaviour as the firm being regulated, it could simply direct the firm to implement its chosen plan, provided that the agency possessed sufficient powers to do so. Indeed, it would then be better simply to appoint the regulatory agency to run the enterprise, rather that to leave decision-making authority with the managers of the firm. But of course decision makers within the firm are generally far more knowledgeable than regulators can be about the circumstances facing them, and the regulator can neither observe nor infer all aspects of the firm's behaviour."

The corporatisation and eventual privatisation of utility companies indicates how policy makers believe it is more efficient to remove direct state control of these enterprises. The creation of a regulatory regime is not intended to replace state control. Economic regulation just modifies the incentives facing regulated companies, so that their behaviour more nearly serves the public good.

The reason for focusing on incentives is the inability of regulators to know what is efficient behaviour. Major authors capture this uncertainty in two forms:

- Regulators cannot observe the "non-money" cost of the *managerial effort* needed to increase efficiency; and

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[19] Vickers and Yarrow, 1988, pp91-92.

- Regulators cannot disentangle the effects of managerial effort from other *random determinants* of total cost.

In this context, "non-money" costs mean costs that do not appear as a cost in the firm's accounts, because they are an expense to shareholders made out of profit. The term might include special incentive payments to management or any costs that shareholders incur themselves in order to scrutinise the firm's management. The random determinants of cost would include both factors that vary *between companies* and unpredictable factors that vary *over time*.[20]

Laffont and Tirole[21] offer a simple case in which regulated firms are either efficient or inefficient, but the regulator does not know which firms are efficient and which are not. They deduce that the outcome of optimal regulation under incomplete information is:

- Efficient companies put in an efficient level of effort and earn a positive rent (ie a profit above the cost of capital);
- Inefficient companies put in "undereffort" and earn no rent (ie their rate of return equals the cost of capital).

Because regulators can never know what the efficient level of costs would be, they cannot insist that regulated companies *incur* only the efficient level of costs, and they cannot *set revenues* equal to the efficient level of costs (except by chance). Instead, regulators can only amend the incentives of regulated companies so that they *reveal* more efficient cost levels through their behaviour.

Once the company has revealed this more efficient level of costs, the regulator can lower prices - although, as discussed above, doing so lessens the incentive for the company to reduce its costs.

## 3.2. Can the Regulator Act Independently of the Past?

As discussed in section 2.1, regulation is a substitute for long-term contracts in an industry characterised by long-term investments. However, long-term contracts are normally "incomplete", in that they do not anticipate every contingency that may arise, because of the costs of fully specifying a contract for all occasions. Regulatory procedures suffer from the same problem, which Laffont and Tirole identify as a "transactional constraint".[22] Any

20 See Laffont and Tirole, p55. Their model defines costs ( C) as equal to $\beta$ - e, where $\beta$ is a random variable and e is the cost-reducing effect of managerial effort.

21 Laffont and Tirole, p59.

22 See Laffont & Tirole, pp3-4.

regulatory regime occasionally requires a review or renegotiation to reset prices and other terms, in the light of unanticipated changes in conditions.

At such times, regulators could set prices at different levels. Many commentators have noted that regulators have a strong incentive to re-set prices as low as possible, because of political pressures and incentives. Prices must at least equal marginal costs,[23] if the regulated company is to have any incentive to continue operations, even in the short-term. However, since natural monopolies exhibit economies of scale,[24] marginal costs are *by definition* less than average costs. Specifically, marginal costs exclude the unrecovered sunk costs of long-lived irreversible investments. Hence, setting prices equal to marginal costs will systematically prevent regulated monopolies from recovering their total costs. The incentive for regulators to act in this way creates a problem of *credibility*, which undermines the incentives for efficient long-term decisions by investors.

### 3.2.1. The problem of regulatory commitment

Vickers and Yarrow[25] recognised the problem in 1988, in a discussion of "Credibility, Commitment and Underinvestment". They discuss an example where investors first commit funds to an irreversible investment and then the regulator sets the price. Any regulator who wished to maximise consumer benefits or social welfare would, in these conditions, set price equal to marginal cost. Consequently, investors would not be able to recover the non-marginal costs of investment. The result, say Vickers and Yarrow, would be underinvestment, a lower capital-to-output ratio than is efficient, and higher costs for any given level of output.

Professor David Newbery provides a simple "game-theoretic" model of this problem.[26] He begins with a "one-shot" game, like that described by Vickers and Yarrow, where investors invest and then the regulator sets prices equal to marginal cost. He concludes that no investment will take place in such conditions.

To overcome the reluctance to invest, so that consumers receive the services they want, regulators must make a prior "commitment" to allow regulated companies to recover their total costs, before they make the investment. The difficulty facing regulators is the incentive they face to ignore this commitment when the time comes to reset prices. Successful regulation relies on such commitments being credible.

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23 "Marginal cost" is a standard economic term. It refers to the additional cost incurred to increase output by one unit, or the cost avoided by reducing output by one unit. This cost concept excludes "fixed costs" that do not vary with output.

24 See section 2.1.

25 Vickers and Yarrow, 1988, pp88-89.

26 D.M.Newbery, p30ff. Newbery devotes an entire chapter to "The Problem of Regulatory Commitment".

Newbery shows that regulatory commitments can be credible in a "repeated game", ie if regulators repeatedly demonstrate a willingness to abide by previous commitments. He shows that consumers benefit from regulators abiding by previous commitments if they wish to encourage continued investment by the monopolist.

### 3.2.2. Incentives in a repeated game with long-term investment

Newbery expands his model to cover multiple periods and uncertainty as to whether demand will be "high" or "low" in each period. In this framework, the regulator now has to encourage the regulated firm to invest for the future. Furthermore, the regulator can now *demonstrate* whether or not his commitments are credible, by not setting prices equal to marginal cost, and allowing the firm to charge its average cost. The regulator can still choose at any time to set prices equal to marginal cost (rather than average cost), but the incentive to do so is greatly reduced. The regulator knows that "cheating" on a prior commitment to allow total cost recovery will undermine incentives for investment in the future.

In a repeated game such as this, many outcomes are possible, involving more or less "cheating". Newbery examined the conditions in which an *immortal* regulator would succeed in encouraging a firm to invest forever in enough capacity to meet "high" demand. He found that this beneficial outcome would emerge if:

- The expected net benefit of additional capacity
- *is greater than*
- the cost of the required capital investment.[27]

For network utilities, this condition is normally fulfilled, and it is efficient to act consistently with past commitments, as long as the regulator does not expect excess capacity to persist for many years (in which case the net benefit of additional capacity is small).

### 3.2.3. Implications for price cap regulation

These observations imply that regulators cannot set revenues at individual reviews without taking into account their effect on the credibility of the regulatory regime. In particular, regulators will only encourage investors to make long-term investments in the future, if they can credibly promise to permit investors to recover the associated costs. In assessing such promises, investors will look at whether regulators have allowed the recovery of past investment costs. Regulators that deny the recovery of past (sunk) costs will find it difficult to offer the reasonable prospect of cost recovery needed to induce efficient investment in the future.

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27 Newbery's formula compares the net benefit of making a unit of capacity available, times the probability of high demand (1-P), against the unit cost of investment (r). The net benefit of capacity is the difference between the marginal cost of using capacity (b) and the marginal cost to consumers of the alternative (c). Hence, his condition for successful regulation is $(1-P).(c-b)>r$. See Newbery, page 38.

This finding applies equally to cost of service regulation and to price cap regulation. Price caps may, at various times, be different from the level of actual costs. However, this does not mean that regulators can set price caps without reference to actual costs. Any regulatory regime that fails to offer credible promises of cost recovery will be unable to capture all the potential efficiency benefits of price cap regulation. In fact, a price cap regime that loses credibility (because regulators continually redefine the terms of the bargain to deny cost recovery) may be less efficient than a simple system of cost pass-through.[28]

To provide the necessary credibility, regulators must demonstrate that they have overcome the temptation to act "opportunistically", ie to prevent recovery of sunk costs. This does not mean that regulators must *guarantee* total cost recovery (even if they could), as such a guarantee would eliminate incentives for cost minimisation. It does mean, however, that individual regulators must reach decisions on an *objective* basis that is *consistent* with past commitments. This finding has implications both for the design of the legal framework (which I discuss briefly in section 3.3) and for the choice of method used to set the price cap (to which I return in section 4.2).

## 3.3. What Role Do Legal Constraints Play?

The main omission from Newbery's model is recognition that most regulators have a short tenure in their post, and that their objectives differ from that of an "immortal" regulator. For a variety of reasons, individuals can be expected to have shorter term objectives, or to give more weight to short-term outcomes. The economic pressures identified by Newbery explain why "society" wishes to encourage long-term investment, but not why individual regulators would wish to do the same.

Newbery recognises that societies impose long-term objectives upon individual regulators by restricting their discretion through legal instruments and procedures, or what Laffont and Tirole call "administrative constraints".[29] In discussing US and other regulatory regimes, Newbery writes:[30]

> "....the predictability, and hence credibility, of regulation rests heavily on established procedures enabling the regulated industry to appeal against unreasonable regulation....Where these established procedures are not available or where administrative law does not adequately restrain discretion, very specific regulatory legislation may be required...."

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28 D.L.Weisman, *Superior Regulatory Regimes in Theory and Practice*, Journal of Regulatory Economics, 1993, No 5 p355-366.

29 Laffont and Tirole, p4.

30 Newbery, p56.

Vickers and Yarrow also recognise that the law has a role to play in restricting the discretion of individual regulators. They quote the following suggestion from Greenwald, referring to the legal obligation on US regulators to offer a 'fair' rate of return on all investments:[31]

> "Restricting regulators with an appropriate 'fairness' criterion may, therefore, be essential to the viability of the originally optimal equilibrium. The simplest way to do this would be to require by law that past regulatory promises must be honored in future proceedings."

In principle, the desire to restrict regulator's incentive and ability to engage in *short-term* opportunism applies equally to the legislature. Hence, in the US, for example, the rights of investors have been defined and protected by the Federal Supreme Court, on the basis of the United States Constitution, rather than by individual laws. (See section 3.5.)

## 3.4. What Regulatory Outcomes Are Feasible?

The constraints listed above - summarised by Laffont and Tirole as "information", "transactional" and "administrative and political" constraints - limit the range of feasible outcomes. Regulation has to be conducted in the knowledge that some desirable outcomes may simply be impossible to achieve. In particular:

- Regulatory commitments must be credible to encourage efficiency; in an industry with long-term irreversible investments, the regulator's past behaviour affects future incentives;
- To provide credible incentives, regulators must minimise the use of subjective discretion, by adopting regulatory methods that are objective and consistent over time.
- Regulators cannot *know* efficient costs; the purpose of incentive regulation is to *reveal* information about efficient costs; in the mean time, objective regulatory methods will set price caps on the basis of information about actual costs.
- Regulation has a cost: linking revenues to costs affects incentives and raises costs, but the regulatory outcome is still judged better than unrestricted monopoly, because prices are lower and outputs are higher.

In addition, regulators must abide by any legal constraints imposed upon them by the legislature. Such administrative constraints (to use Laffont & Tirole's terminology) are required to align the short-term objectives of the regulator with the long-term objectives of society.

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[31] B.C.Greenwald, *Rate Base Selection and the Structure of Regulation*, Rand Journal of Economics 1984, No 15, p85-95. Extract from p86, quoted in Vickers and Yarrow, p 89.

## 3.5. What Are the Principles of Regulation?

The previous sections have identified the need for regulation of natural monopolies to meet various criteria. The level of revenues or tariffs must promote efficiency, both productive and allocative. Revenues must remain sufficiently close to costs to promote *long-term investment* and *allocative efficiency*, but should deviate from costs to the extent needed to offer additional rewards for *productive efficiency* (cost minimisation). The process for revenue setting must be *objective* and *consistent* over time, so that regulatory commitments are *credible* and future revenues are *predictable*.

These principles are expressed in a variety of formats, by various authors, but are well summarised by Bonbright, as the attributes of a good tariff setting procedure. Dr. James C Bonbright was the distinguished author of the first edition of Principles of Public Utility Rates, one of the most cited references in the regulation of utilities. He observed the process of regulation in the US over more than fifty years and his list of principles therefore encapsulates a wide range of practical experience. The principles advocated by Bonbright are supported in a number of other academic authors writing on regulation including Breyer[32] (now a US Supreme Court judge) and Phillips.[33]

Bonbright identifies 10 detailed attributes of a good tariff setting procedure,[34] which he then summarises into three "primary criteria" and one "secondary criterion" for judging tariff-setting (ie regulatory) procedures.[35] Bonbright's criteria are described below.

### 3.5.1. Capital attraction

Bonbright states that tariffs must provide a revenue sufficient to meet the "fair return standard with respect to private utility companies". This principle encapsulates the need for regulators to offer a reasonable prospect of cost recovery, so that regulated companies can attract capital for investment. Bonbright derives his formulation of the principle from two important cases of the US Supreme Court. The Bluefield decision[36] established in 1923 that regulated companies were entitled to earn the same rate of return as other companies, allowing for differences in risk and other circumstances, so that they can attract capital from potential investors. The Hope Gas decision[37] established in 1944 that revenues had to cover both operating costs, and capital costs (ie "the return on and of capital").

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32 Breyer, S G (1982) *Regulation and its Reform* Cambridge, Mass.: Harvard University Press

33 Phillips, C F Jr. (1993) *The Regulation of Public Utilities* Arlington, Virginia: Public Utilities Reports Inc.

34 Bonbright et al, p383-4.

35 Bonbright et al., p385-7.

36 Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia (262 U.S. 679, 1923)

37 Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944)

This condition reflects the principle of "individual rationality" used in academic writings,[38] which states that rational regulated companies will only provide a service if they expect a non-negative profit (after recovering all costs including the cost of capital).

Bonbright also points out that the definition of a "fair return" incorporates any variation in returns needed to encourage management (ie productive) efficiency.[39]

### 3.5.2. Consumer rationing

Tariffs should, says Bonbright, "discourage the wasteful use of public utility services while promoting all use that is economically justified". This principle ensures that tariffs (and hence total revenues) reflect costs and promote allocative efficiency. Given the need for total cost recovery, this criterion affects primarily (1) cost allocation between tariffs and (2) individual tariff design. However, the desire to keep prices in line with economic costs and to promote efficient usage may also affect (3) the valuation of assets, and (4) the allocation of depreciation charges through time.

### 3.5.3. Fairness to ratepayers

Bonbright defines this standard as follows: "total revenue requirements must be distributed fairly and without arbitrariness, capriciousness, and inequities among the beneficiaries of the service". This criterion covers real, but non-economic, criteria of "fairness" that affect the allocation of costs between different customer classes. However, the need to avoid "arbitrariness, capriciousness and inequities" is a general procedural requirement, which leads to Bonbright's "secondary" criterion for regulatory procedures, ie stability and predictability.

### 3.5.4. Stability and predictability

Bonbright discusses at length the need for stability and predictability as a secondary but nonetheless important criterion for tariff setting.[40] The key points he raises are:

> *"In ratemaking, the attribute of predictability is more important than stability per se...One could certainly argue that ratepayers should be given the information they need to predict rates accurately. However, this does not imply a necessary need to keep rates stable at the expense of otherwise efficient pricing."*

Most costs in the electricity sector, including many operating costs, depend upon long-term investment decisions. The most efficient tariff and revenue-setting procedures are therefore likely to be those that foster efficient long-term decisions. Investors will be discouraged

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38 See Laffont and Tirole, p57, and Schmalensee, p422.

39 Bonbright et al, p385-6.

40 Bonbright et al, p387-388.

from making efficient long-term commitments, if the revenue setting methodology appears to be random ("capricious"), subjective ("arbitrary") or opportunistic ("inequitable"), because unpredictable changes in revenue setting procedures can make investments become unprofitable. Tariffs and revenues may change as costs change. However, the use of stable and predictable procedures to convert costs into revenues enables the regulator to signal a long-term commitment, by applying objective standards that are consistent over time. This ability to signal such commitments makes an important contribution to efficiency and to consumer benefits.

### 3.5.5. Summary

Bonbright's principles of tariff-setting are drawn from practical observation of regulatory procedures over many years. They apply to any regulatory decisions, in any regime, although they may be expressed differently according to local custom. In general, I would summarise them as the requirement to offer a *reasonable prospect of total cost recovery*. By this phrase, I mean that regulators should adopt objective and predictable procedures for setting revenues, such that the resulting revenues allow the company to earn a rate of return comparable with the rate earned by other companies (after allowing for any difference in the risks they face).

The scope of the required procedures is as follows:

1. Rules to derive total revenues from objective definitions of costs at each review;
2. Rules to convert total revenues into tariffs; and
3. Rules to update total revenues or tariffs over time between reviews.

As discussed in section 3.1, companies of normal efficiency should earn a normal rate of profit; any company that manages to improve its efficiency faster than normal might be expected would earn a higher rate, and vice versa.

How much the rate of return should rise to encourage efficiency improvements is a matter for the regulator to decide when setting the initial revenue allowance and when defining the rules for updating revenues over time. The decision requires an understanding of risk of variation in actual profits under different schemes.

The next section discusses how regulators should set revenue controls, on the basis of the principles listed above.

# 4. BEST PRACTICE REGULATION

This section describes how regulators would be expected to approach the task of setting a revenue control formula for a natural monopoly, such as an electricity network, given the principles and constraints set out in previous sections.

## 4.1. What Is the Appropriate Level of a Price Cap?

The starting point for setting a price cap is information on the actual costs of the company concerned, for several reasons.

### 4.1.1. Use of information on actual costs

In the first place, the principles of individual rationality or capital attraction discussed in section 3.5.1 require that total revenues should provide a reasonable prospect of total cost recovery. Section 3.2.3 explains the need for regulators to adopt consistent treatment of the sunk costs inherited from past decisions, in order to preserve the credibility of regulatory commitments. Regulators must therefore take account of actual costs.

Second, section 3.2.3 also explains that regulators need to adopt *objective* methods, which requires that revenues are based on cost information shown in accounts prepared according to established principles.

There can be no presumption that revenues must be based on "efficient costs". In the first place, a regulator will never *know* in advance what efficient costs "should" be; the aim of regulation is to *reveal* efficient costs by providing an incentive for regulated companies to operate efficiently. Internationally, there is no agreed understanding of the cost function of an electricity network business, given that its costs depend on both local topology and past decisions made with imperfect information. Hence, regulators cannot derive a figure for what total costs "should" be, by applying statistical techniques to cost conditions in other companies. Statistical estimates of "efficient costs" are too subjective to provide a long-term reasonable prospect of cost recovery, and would undermine incentives for efficient investment.

### 4.1.2. Objective basis for disallowing costs

Basing revenues on actual cost information does not mean that all actual costs must be passed through. Regulators may disallow individual cost items shown to be inefficient, as a means to encourage higher efficiency in future. However, such disallowances must conform to the need for objectivity and consistency in all regulatory methods. That means that the regulator must produce good reasons for disallowing costs, in order to avoid creating the suspicion that the disallowance is merely an opportunistic decision to reduce prices. These good reasons must be based on objective evidence, not merely subjective judgements. This evidence must relate to the efficiency of the decision to incur the cost, not to the subsequent effect on prices.

For instance, in appraising a past investment, a regulator would need to show that the decision to make the investment was inefficient or imprudent, *given the information available at the time*. Out of any long-term investment portfolio, some investments are bound to be underutilised or even redundant, because demand fails to materialise at the expected level. *Subsequent* evidence that an investment is not needed is not, however, evidence of inefficiency in the original decision. In the US, for instance, costs are eligible for compensation if "prudently incurred".[41]

Attempts to deny the recovery of underutilised investments will not encourage efficient decisions, but will merely make investors less willing to carry out efficient investment if there is a risk of underutilisation. Hence, regulators' decisions should not penalise regulated companies for failing to possess perfect foresight, but only for acting in a demonstrably inefficient manner at the time of the decision to invest.

Some regulatory rules systematically deny cost recovery, such as the US standard that an asset must remain "used and useful". Some assets are bound to be underutilised and the investor would therefore always be denied a chance to recover some costs.[42] However, as long as the regulator applies such a rule predictably, investors will take it into account and efficient investment will still proceed. For instance, if a particular rule leads to cost recovery being denied for one twentieth of all investments, investors will increase the required rate of return by one twentieth.[43] In such instances, the *predictability* of the rule ensures that total revenues continue to offer a *reasonable* prospect of cost recovery.

### 4.1.3. Capping prices, not expenditure

It is important to stress that price caps must be based on objective measures of actual costs, because some writings convey an incorrect impression about the way price caps encourage efficiency. Informal comments sometimes suggests that *lowering* a price cap will encourage greater efficiency in itself, or that setting a price cap "too high" will encourage *in*efficiency. When such arguments emerge (eg as a reason for setting price caps equal to "efficient" costs) they display a lack of understanding about how price caps work.

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41 Bonbright et al. p138.

42 The "used and useful rule" sometimes promotes inefficient use of an asset that should remain idle, because otherwise the company would be unable to recover the asset's investment cost. Whilst not normally a problem for transmission lines (which remain charged as long as they are connected to the grid), the rule can lead an electric utility to dispatch all its generators, even when it would be cheaper to put some into mothballs or retirement.

43 Strictly speaking, this increase applies to the total return *on* and *of* capital, ie to depreciation and the cost of capital. If depreciation allowances are unchanged, investors will extract the extra revenue through an increase in the cost of capital alone – or else investment will not take place efficiently.

In public agencies, the profit motive is lacking and managers may have a private incentive to spend money. In such cases, central authorities might set a cap on total expenditure as a way of preventing unnecessary expenditure. The cap itself acts as a constraint on spending; lowering the cap reduces the amount the agency can spend, which may improve efficiency. However, price caps work quite differently on privately owned companies.

The efficiency of private companies is driven by the profit motive. A price cap only encourages companies to reduce their costs, because cutting costs results in higher profits. Lowering the price cap will have no effect on this incentive, because the net benefit from cutting costs remains the same. A private company's annual expenditure is not limited in any one year by the price cap, since price caps for network utilities include an allowance for recovering sunk costs from past years. However, if a regulator ever set prices so low that the regulated company could no longer finance its desired level of expenditure, there is no guarantee that the resulting cuts in expenditure would be *efficient*. Hence, cutting price caps below the level of actual costs without good reason would not improve incentives for efficient operation (or use) of the network. It would, instead, undermine the apparent objectivity and consistency of the regulatory regime, discourage efficient investment and promote excess demand. Arbitrarily cutting price caps therefore runs counter to regulatory objectives.

## 4.2. How Should Regulators Set Price Caps?

This section sets out in broad terms how regulators should gather the information needed to set a price cap, in order to abide by the principles listed above.

### 4.2.1. Observed costs

To base price caps on objective information, regulators need to proceed from the company's own accounts for a recent year. To ensure that such information is objective and not subject to dispute, the regulator needs to establish the standards by which information is collected and shown in the accounts. To a large extent, these standards can be derived from established practice (eg tax law), but some additional rules may be required solely for regulatory purposes (eg allocation of costs between different regulated and unregulated services). These accounting rules represent a large part of the "stable and predictable procedures" described by Bonbright.

These observed costs can then be adjusted to provide a reasonable allowance for the future. Such adjustments take the following forms.

### 4.2.2. Objectively determined disallowances

As discussed above, the regulator may decide, in interests of efficiency, that certain costs should not be covered by the price cap. In principle, decisions of this nature should be objectively based on the information available at the time when the expenditure was incurred. In practice, this means that regulators need to investigate individual decisions in some detail.

#### 4.2.3. Additional costs due to new commitments

In the time since the accounts were last prepared, the regulated company may have taken on new commitments that will incur additional costs. These commitments may be new services that the company is obliged to offer, or new investments that the company has carried out recently or is contractually committed to carry out in the future. In either case, the regulator needs to increase the allowance for costs, compared with what was shown in the accounts of past years.

#### 4.2.4. Incentive allowances carried over from the previous regulatory period

The institution of periodic regulatory reviews creates a discontinuity in incentives, because prices are reset in line with costs at infrequent intervals. If a regulated company cuts its costs in the first year *after* a review, it keeps the cost saving (as higher profit) for several years, until the next review. On the other hand, cost savings in the last year *before* a review will be passed through to customers immediately. The higher profit earned in the former case biases the regulated company towards making cost savings just after a periodic review, even if it would be more efficient to make the cost saving earlier.

For this reason, there has been some discussion of schemes to smooth incentives, by "rolling forward" cost savings from the last regulatory period and allowing the company to recover a share of them in the coming regulatory period.[44] In practice, such schemes only have any relevance for incentives if they can be anticipated, because they are announced in advance.[45]

#### 4.2.5. Updating by reasonable trend rates of change

Once the regulator has calculated an objectively determined level of costs for a recent year, this cost must be updated to provide a cost figure for the year in which the price cap is being defined. The starting point for a price cap may be set equal to expected costs in the coming year, or for a year further in the future.[46] The price cap formula must then allow the price cap to be updated for expected trends in future costs.

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[44] See, for example, OFWAT Open Letter MD145, *To managing directors of all water and sewerage companies and water only companies; the framework for setting prices*, 8 March 1999.

[45] For a discussion of the issues surrounding such incentive mechanisms, see chapter 6 of Office of the Regulator-General, *2001 Electricity Distribution Price Review: Draft Decision*, Victoria/Australia, May 2000.

[46] In work for the Dutch telecoms regulator OPTA during 1999, NERA updated information on KPN's *actual* costs in 1998/99 by reference to trend rates of change in demand and efficiency, in order to estimate expected costs at the *end* of the coming regulatory period (ie in 2001/02). This estimate of future costs provided the basis for the price cap in that year. Price caps in intermediate years were defined as intermediate between current price levels and this future price cap. OPTA subsequently adopted this approach. See Nigel Attenborough et al, *A Price Cap Model of KPN; Final Report for OPTA*, NERA, September 1999.

In updating the cost estimate, and in defining the price cap formula, good regulatory procedures use objectively defined rates of change. Where a forecast is used (eg to update a cost estimate for a future year, or to set the trend in efficiency), that forecast should be derived from objective information (such as historical long-term trends), not from the subjective (and potentially conflicting) opinions of experts. Where it is possible to use an index (eg of inflation), the index should be compiled independently and publicly observable.

## 4.3. How Should Regulators Design the Price Cap Formula?

Given the level of total allowable costs and an estimate of demand for a base year, the regulator can specify a revenue formula for that base year in terms of (1) a fixed revenue cap, or (2) an average price cap,[47] or (3) caps on individual tariffs and charges. All such revenue formulae must be updated to allow for predictable changes in costs and the regulatory regime as a whole must also accommodate unpredictable changes in conditions. The following sections set out the principles for making such adjustments.

### 4.3.1. Inflation

To allow for inflation, costs are updated using independently compiled indices of costs. Where regulators have a choice over which price index to adopt, it is rational to adopt the index that most accurately captures the likely rate of increase of costs within the regulated company. In many cases, the Producer Price Index (PPI) or the "Gross Domestic Product Price Index" (GDPPI) best achieve this aim, because they reflect the costs of inputs in general, but regulators may choose the Consumer Price Index (CPI) if it is more stable and so better tracks the costs of long-lived investments.

### 4.3.2. Efficiency growth

Regulated companies are expected to become more efficient in their use of inputs over time and regulators anticipate such efficiency growth by updating price caps (and cost estimates) by the *expected annual rate of efficiency growth*, often denoted by "x". By altering the level of "x", a regulator can change the level of the price cap and hence of revenues earned by a network company. However, as discussed in section 4.1.3, regulators promote efficiency to the extent that they fix price caps exogenous to costs; they do not promote efficiency by capping the level of expenditure. Hence, regulators will not promote greater[lesser] efficiency in the short-term by, for instance, setting a higher[lower] value of "x" in order to lower[raise] the price cap. Instead, it is conventional to set "x" at the level necessary to ensure that revenues stay in line with expected costs, that is at the level of expected growth in efficiency (and hence the expected decline in real unit costs, before allowing for inflation).

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47 Average price caps can take many different forms, depending upon the weights accorded to different elements of a company's tariffs, but I do not intend to discuss these details here.

We discuss in section 4.5 the objective methods available to regulators for setting "x". To apply the principles set out above, regulators should set the target rate of efficiency growth by reference to average *long-term* rates of efficiency growth *observed* in comparable companies. Regulators do sometimes impose a higher rate of efficiency growth, but should only do so if they can show good (ie objective) reason. In general, it is only reasonable to expect a private company's efficiency growth to *accelerate* relative to the rate observed in the past, if incentives for efficiency are *stronger* than in the past. Asserting that a company is less efficient than others provides neither an objective basis nor a logical reason (see section 3.1) for expecting the company to improve its efficiency faster in the future than in the past.

#### 4.3.3. Demand

As demand increases, so costs will be expected to increase. A price cap provides an automatic increase in revenues, because the revenue allowance is the product of (1) an average price cap and (2) an index of demand. The regulator may define the average price cap as a simple average revenue per unit of demand ("revenue yield"), or as a weighted average of particular prices ("tariff basket"). If the regulated company sells a number of products - such as energy and capacity, or network services at different voltages - the regulator must also specify an index of demand (ie a weighted average of various demand measures). Otherwise, the level of "demand" is not uniquely defined.

Not all network companies operating under incentive regulation are subject to an average price cap. In some cases, the balance of products provided by the company will change unpredictably, in which case the regulator may set separate price caps for separate bundles of services. For instance, the UK gas transmission and distribution business (Transco) has operated for some time with separate price caps for deliveries to large and small customers.

In the short-term, additional demand may be incorporated at little or no extra cost, because investments in transmission capacity are "lumpy" and create spare capacity. Future investments may be fully committed, such that future costs are predictable. For this reason, the revenue allowance for an electricity transmission company may be a fixed revenue, rather than a price cap.[48] For example, distribution (ie low voltage network) companies in the UK have since 1994 received an allowed revenue that is made up of (1) a fixed revenue allowance and (2) a price cap per unit distributed. Both elements are indexed to inflation and efficiency growth, with each element providing roughly 50% of total revenues. From 1993 to 2001, the National Grid Company's (NGC's) transmission business operated under a control that defined a fixed annual revenue, indexed to inflation but not to any measure of demand.

[48] The British electricity regulator has adopted this approach for the National Grid Company's main source of transmission revenue since 1993.

### 4.3.4. Other unpredictable changes

To limit regulatory risk further, it is necessary to devise explicit contingent allowances and procedures for other *unanticipated* changes affecting the company's financial position, which cannot be captured by an index. Examples include one-off costs associated with restructuring, redundancies, storms and pensions, or extra capital expenditure that requires explicit acknowledgement.

To avoid unnecessary risk, the regulator and the company need to set out pre-agreed contingent extra allowances for such unanticipated events, or at least clear arbitration rules for resolving any disputes. The presence of such arrangements greatly reduces the company's revenue uncertainty and the scope for regulatory opportunism.

A good example is provided by a recent reform of the control on NGC's transmission business. Both NGC and Ofgem (the British energy regulator) have consistently failed to agree an accurate forecast of future capital expenditure on reinforcing the network to accommodate new generators. Variation in the timing of new connections led to significant differences in capital expenditure and (less significantly) NGC's annual costs and profits. Nevertheless, to reduce the problems caused by forecasting errors, the latest review of NGC's revenue control has instituted from 2001 an automatic adjustment of £23 million per GW of new connections by generators. This approach recognises the inherent uncertainty over the volume of new connections, whilst retaining a revenue formula that gives NGC an incentive to minimise costs.

### 4.3.5. Summary

When defining a price cap (or a revenue cap or similar), regulators face a choice between different methods of allowing for changes in unit costs. Some changes in costs are relatively stable and predictable, whilst some changes in cost are unpredictable.

If a factor affecting costs changes at a predictable rate, it can be specified in advance without running the risk that allowed revenues will deviate wildly from costs. This approach is usually adopted when setting "x", the expected rate of efficiency improvement, because it does not vary much from year to year for network utilities (whose costs are largely sunk).

If the rate of change in a factor is unpredictable (as many people still regard inflation), the price cap must incorporate an index that captures the effect year by year. The inclusion of the CPI, for example, allows the price cap to be updated in line with unpredictable changes in the rate of inflation. To preserve incentives, such indices need to be objectively determined by independent parties. Procedures should also be set up to deal with unpredictable changes that cannot be captured by an index.

## 4.4. How Should Regulators Define Costs?

When the regulator decides to set tariffs on the basis of network business' costs, a definition of such costs is needed. This definition should follow established regulatory principles.

### 4.4.1. Cost categories

It is conventional to divide the costs of a regulated network utility, characterised by long-lived investments, into three components:

1. Operating expenditures;
2. Depreciation (also known as the return *of* capital);
3. Cost of capital (also known as the return *on* capital).

Operating expenditures are "charged" as a cost in the same year they are incurred. A regulated company normally expects to recover such costs from revenues received in the year concerned. However, when a regulated firm makes a capital expenditure (for instance if it buys a long-lived asset), such expenditure is not charged as a cost in that year, but is distributed and charged as a cost ("depreciation") over the estimated useful life of the asset. A regulated company would therefore expect to recover such costs over many years.

Until the firm's capital expenditure is returned through depreciation charges (the return of capital) the firm faces an opportunity cost for those funds which remain "tied up" in the asset. This opportunity cost (known as the cost of capital) can be measured by what the firm's shareholders could gain if they chose to invest the funds elsewhere, that is "the expected rate of return prevailing in capital markets on alternative investments of equivalent risk".[49] The funds "tied up" in undepreciated assets are known (in the UK) as the "Regulatory Asset Value".

### 4.4.2. Information sources

As discussed above, regulators can only amass objective information on a company's costs from accounts prepared according to agreed principles. These principles may be the same as those used to compile the company's own accounts, or they may be defined differently for regulatory purposes. In defining different accounting principles, of course, regulators must adhere to the principles of regulation, if they are to avoid behaving (or appearing to behave) opportunistically in ways that undermine the investors' prospects for cost recovery.

A particular concern for investors is the value placed on long-lived assets at each price cap review. Changing the basis for valuation affects the prospects for cost recovery. The need

[49] Kolbe, A L, Read J A Jr., and Hall, G R (1986) The Cost of Capital: Estimating the Rate of Return for Public Utilities Cambridge, Mass.: The MIT Press, p13

for consistency and predictability in regulatory methods dictates that, from one review to the next, accounting principles should not change (without good reason - see section 4.1.2) in ways that affect the total value that investors recover over the life of the asset.

### 4.4.3. Asset valuation

The most objective basis for valuing an asset is its cost. However, the cost of an asset to its owner can differ according to when the owner acquired the asset. Bonbright discusses at length[50] which definition regulation should take into account:

- the asset's "original cost" - ie the cost incurred when the asset "first entered public service"; or
- the asset's "acquisition cost" - the cost at which the existing owner purchased the asset.

After reviewing regulatory experience, Bonbright concludes that, in nearly all circumstances, regulation should be based on the "original cost". His conclusion is intended to prevent owners from increasing the value of an asset merely by overstating it in a sale from one owner to another. However, he cites "an exception". Bonbright argues that the use of acquisition cost may be justified if the transfer was "an essential, or at least a desirable, part of a program[me] of integration, justified in the public interest for the purpose of securing operating efficiencies that would offset any unavoidable excess in acquisition costs over original cost."[51] He does not define "a programme of integration", but I would interpret his qualification as including any programme of asset transfers that restructures an industry in order to make it more efficient (and which therefore lowers prices). This definition would encompass business separations, as well as privatisation (ie transfer of a company from the public to the private sector) and, possibly, flotation (ie the first sale of shares on the stock market).

### 4.4.4. Cost of capital

The cost of capital is the only cost item *not* visible in the accounts, since it includes the cost of equity that must be estimated from data on the stock market. (The cost of debt can - and should - be derived from the accounts.) In estimating the cost of equity, the aim is to provide a rate of return that is comparable to that offered by other companies with a similar risk profile, so that the regulated company can attract capital for investment.

Various methods of estimating the cost of equity are available, including the Capital Asset Pricing Model (CAPM), Dividends Growth Model and Asset Pricing Theory. Each method has advantages and disadvantages, associated mainly with the availability of data. In

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[50] Bonbright et al, p238-242

[51] Bonbright et al, p241

practice, the regulator can adjust the outcome of any method so as to provide higher or lower returns, eg by giving a more or less generous allowance for future taxes. The most efficient approach is to set up a formula using, as far as possible, observable and independent data, so that the *scope for discretion and dispute is minimised*. The formula should then be changed only if there is strong evidence that the company cannot attract capital, or has an excessive incentive to invest.

The allowed rate of return can be defined in nominal terms (ie as observed in financial markets), or in real terms (the nominal rate, less the inflation rate). Whichever method is chosen must be consistent with the approach to asset valuation. If assets are depreciated at their historic cost, the regulator must offer compensation for inflation by allowing the nominal rate of return. Conversely, if assets are revalued each year, the allowed rate of return must be reduced by the same rate of revaluation.[52] Otherwise, over the long-run, the company's rate of return will bear little resemblance to the rate of return in other industries.

As I note above, CAPM is one of several possible methods used by regulators around the world to estimate the cost of equity, which cannot be observed in a company's accounts. The CAPM formula derives a cost of a company's equity from statistical data about (1) the risk free rate of return, (2) the rate of return offered by the stock market, and (3) the correlation between stock market returns and the return on the company's equity, commonly known as the company's "beta". More details on CAPM are provided in box 1 on page 31.

## 4.5. How Should Regulators Set X?

As discussed above, the conventional interpretation of "x" in a "cpi-x" formula is the expected rate of efficiency growth for the company concerned. Several regulators (in the UK, the Netherlands and Spain, for example) have tried to adapt methods of "benchmarking" for the purpose of setting "x". Appendix B contains a discussion of benchmarking techniques in general (and Data Envelope Analysis in particular) that explains that benchmarking is too subjective to be a suitable technique for use in regulation and is in any case useful for setting "x". Any objective basis for estimating this rate of growth would adopt the following approach:

1. Estimate the rate of efficiency growth achieved by comparable companies in the past;
2. Adjust this rate for any objectively determined differences between this set of comparable companies and the company being regulated.

I discuss these approaches separately.

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52 This factor is easiest to understand if assets are valued upwards each year in line with movements in the Retail Price Index. The same rate of change can then be deducted from the nominal rate of return. Adjustments are more difficult to calculate and predict, if assets can be revalued by different amounts (eg to reflect replacement costs).

**Box 1: Capital Asset Pricing Model**

CAPM is a method of estimating the rate of return that a particular asset must offer to encourage anyone to hold it. When applied to shares in a company, the CAPM method estimates the cost of raising equity capital.

The formula is based on the theory that investors want higher returns, but try to avoid risk, and that any investor can lower risk by holding a diversified portfolio of assets ("the market portfolio"). In such conditions, any investor will maximise the value of their wealth by holding a mixture of (1) the market portfolio and (2) a risk free asset. The return that investors require of an individual asset (eg a share in a company) then depends exclusively on the extent to which fluctuations in the value of that asset *add to* or *offset* fluctuations in the market portfolio.

If the value of a share generally rises when the market portfolio rises (and vice versa), it is said to be "positively correlated with the market". Such assets add to the riskiness of an investor's holding and must offer a high rate of return.

On the other hand, if the value of a share rises when the market portfolio *falls* (and vice versa), it is said to be "negatively correlated with the market". Such assets offset fluctuations in other assets, reduce an investor's risk, and only need to offer a low rate of return.

The CAPM theory says that the cost of raising capital by issuing a particular share depends only on:

- the risk free rate,
- the "market premium" (the extra return over the risk free rate available from the market portfolio), and
- the degree of (positive or negative) correlation - known as "beta" - between the share and the market portfolio.

These items can be estimated statistically from historical data and the cost of capital for the share concerned can then be derived from the following "CAPM formula":

Cost of equity = risk free rate + [beta x (market rate – risk free rate)]

Other methods can be used to estimate the cost of capital. US regulators tend to favour the Dividend Growth Model, because it requires fewer estimated inputs, but it provides less stable answers after a corporate restructuring (because the input data is changing). UK regulators use a variety of methods to define the cost of capital of regulated utilities, but often use the CAPM formula as a consistency check.

### 4.5.1. Comparable rate of efficiency growth

Electricity networks are characterised by many long-lived irreversible investments. As a result, their efficiency changes only slowly. Even dramatic changes in technology tend to be incorporated only slowly, as new investment replaces old. As a result, variations in the rate of efficiency growth are also relatively minor. For this reason, historical performance provides a good indicator of likely future trends.

In the US, regulators have accepted calculations of the trend rate of growth in "total factor productivity" as a reasonable basis for setting "x". The measurement of total factor productivity is based on the theories of the respected economist Dale Jorgensen. Several experts have standardised the method of calculation to the point where the range of possible results is relatively narrow and disputes have only a minor impact. A NERA study of US distribution companies[53] established that their annual rate of increase in total factor productivity had been around 2 per cent in recent years.

### 4.5.2. Interaction of "x" and price indices

The choice of the price index used in the price cap formula has some bearing on the value chosen for "x". A *consumer* price index measures the rate of change in the prices of *outputs*, which depend on (1) the prices of inputs (producer prices) and (2) the efficiency of the economy in converting inputs into outputs.

Consumer prices = producer prices *times* efficiency of conversion

Changes in the consumer price index therefore reflect changes producer prices and the rate of growth of efficiency in the economy as a whole:

Change in cpi = change in producer prices *plus* change in economic efficiency

Hence, price formulae that incorporate the cpi already include a certain target rate of efficiency growth, that of the economy as a whole. The value of "x" should then represent only the *additional* rate of efficiency growth that the company can reasonably be expected to achieve.

### 4.5.3. Stretch factors

The cpi includes the rate of efficiency growth for the economy as a whole. The long-term historic trend in total factor productivity for (say) electricity networks provides a basis for estimating what additional efficiency growth should be expected of any electricity network. There may also be good reason to expect an individual company to exceed this long-run

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53 Makholm, J D and Quinn (1994), M J, "*X marks the spot: how to calculate price caps for the distribution function*", Public Utilities Fortnightly.

historical rate - primarily if its incentives to cut costs are stronger than in the past. Such reasoning provides US regulators, for instance, with the basis for applying an additional, company-specific "stretch factor" to the value of "x". Based on practical experience, such "stretch factors" rarely exceed one per cent per annum. Box 2 shows the basis on which a US regulator set the x-factor for a gas distribution company in 1996. Appendix A lists some of the x-factors awarded in recent cases in the US.

**Box 2: Setting X: A Case Study**

In its 1996 investigation of the Boston Gas Company's network tariffs,[a] the Massachusetts Department of Public Utilities (DPU) set the x-factor by reference to four factors:

1. A productivity growth index, set at 0.4 per cent per annum based on a nationwide study of gas company productivity growth over 10 years;
2. An input price index, to be updated over time;
3. A "consumer dividend factor" of 1.0 per cent, in recognition of the improved incentives offered by a move from "cost of service to performance-based regulation"; and
4. An " accumulated inefficiencies factor" of 1.0 per cent, to allow for inefficiency due to cost of service regulation in the past.

With the exception of the input price index, the DPU discusses each of these items in terms of annual rates of change in productivity observed at national or regional level, not in terms of comparative levels.

[a] *Massachusetts Department of Public Utilities, Docket D.P.U. 96-50 (Phase I), 2 December 1996*

### 4.5.4. Summary

The value of "x" in a "cpi-x" price cap formula is intended to capture the regulated company's expected rate of efficiency growth. The only objective basis for estimating such a rate is the long-run historical trend observed in comparable companies, adjusted for any identifiable change in circumstances. The only relevant changes in circumstances would be those relating to the *incentives* offered to the company concerned. Practical experience suggests that strengthening incentives will only accelerate expected efficiency growth by about one per cent per annum.

Some companies will manage to exceed the rate of efficiency growth implied by such analysis - and some will achieve less. The resulting variation in rates of return provide the reward for efficiency upon which incentive regulation depends.

## 4.6. Conclusion

Price cap regulation provides short-term profit incentives to improve efficiency because revenues are fixed for a time exogenously to costs, not because the price cap represents a constraint on annual expenditure. To preserve long-term incentives for efficiency, price caps must be set using objective methods that offer a reasonable prospect of total cost recovery. Applying this principle dictates that price caps:

- are set on the basis of actual costs, measured according to agreed accounts principles, and
- are updated by rates of change derived from (1) observable indices (such as the cpi) or (2) historically observed trends (such as efficiency growth).

This principle allows considerable choice over the method used to set a price cap - but rules out many methods) as too subjective or inherently biased against cost recovery.

# 5. ENSURING ADOPTION OF THE BEST METHODS

Application of the regulatory methods outlined in the previous sections can be achieved through the adoption of *required procedures* that aim to ensure that (a) evidence must survive the scrutiny of many other parties and (b) the regulator bases any decision only on such evidence as survives this scrutiny.

The strongest way to enforce this is through a legal requirement for the regulator to follow highly detailed administrative procedures. These procedures may be set out in law, and involve submission, rebuttal and cross-examination of any testimony, and detailed explanations of any decision. Such a system of administrative procedures comprises transparent processes that open up opportunities for appeal, when the regulator's decision does not meet the required standards. The desire to avoid appeals means that individual decision-makers take more care to ensure that the most reliable evidence can justify their decisions, and that they apply key concepts in accordance with the way that they have been defined previously.

If (as in many European countries) regulatory procedures are somewhat underdeveloped, then responsibility to subject arguments to scrutiny rests with the companies who wish to defend their interests. The regulator may not offer a chance for detailed scrutiny of regulatory proposals in formal hearings, but regulated companies should always set down the basis for an appeal to other bodies (including courts of law), but ensuring that flawed arguments do not go unchallenged. Criticism of the regulator's arguments should always be objective and dispassionate, but should always make clear any errors of fact or misunderstandings about the principles of regulation.

## 5.1. Procedural Requirements

Most regulatory procedures around the world exhibit common features designed to support the principles listed above. The absence of any one of these features is problematic, in that the regulator takes on more responsibility for sifting through evidence. Consequently, the regulator has less assurance that the evidence is complete and the industry has less assurance that the regulator will reach a reasoned decision on the basis of all the evidence. As a result, decisions are less predictable. The common features found in most systems are as follows.

The regulator first announces any forthcoming decision, specifying the timetable and procedures for public hearings and initial decisions. After notification of an impending determination, the regulator must give interested parties the opportunity to participate in the decision making process. This participation takes the form of submission of relevant evidence. Evidence will normally include written data, views or arguments, and may or may not include oral presentations.

During most proceedings, the proponent of a decision (ie of a change) has the burden of proof, but this will depend on the local legal framework. Any interested party should be entitled to present his case or defence by oral or documentary evidence, to submit rebuttal evidence, and to conduct such cross-examination as may be required for a "full and true disclosure of the facts".[54]

After consideration of the submitted data, the regulator must then proceed by publishing a concise general statement of the basis and purpose of the decision, based on the evidence received to date. In reaching a decision, the transcript of testimony and exhibits, together with all papers and information request files in the proceeding, will normally constitute the exclusive record for decision (ie the list of relevant evidence). Often, a decision may only be issued on the consideration of the full record, and must be supported by and be in accordance with the evidence presented. Allowing the regulator to take into account "confidential" information will simply allow them to ignore any public evidence. A specific procedure will be established by which an agency may reach a decision, as is what may be included in the document issuing the decision as supporting evidence.

To ensure that regulators are held to these procedures, there normally exists the possibility of appeal for failure to follow these procedural requirements (including a failure to take evidence into account).

## 5.2. Appeals and Precedents

A major feature of administrative process is the well-established requirement that decisions be taken in accordance with precedents established in case law. These precedents effectively help to narrow down the definition of the regulator's powers, which are often expressed rather vaguely in the enabling law. In the US, for example, regulators are expected to reach a decision which is "just and reasonable"; what this means in the context of regulated utilities has been defined by a succession of court cases on appeal. The 1944 Hope case established that just and reasonable regulatory decisions would offer investors a reasonable expectation of earning the opportunity cost of capital. This principle underlies most US decisions about revenue allowances, although regulators enjoy wide powers of discretion in deciding how to enact the underlying principle.

## 5.3. Benefits of Procedural Constraints

UK-based commentators have tended to see administrative procedures as a constraint on the "flexibility" and speed of response of the regulator. European regulators, envious of the freedom available to their UK counterparts, may make similar arguments. However, flexibility is not necessarily desirable for a "stable and predictable" regime. Furthermore, UK regulatory procedures have not proven to be particularly speedy in practice, especially

[54] This phrase derives from the US Administrative Procedures Act, 1946.

when disputes arise. Stringent procedural requirements have several beneficial consequences:

- Testimony is subjected to hard-hitting scrutiny by third parties (through rebuttal and cross-examination), which enables the agency to assemble a reliable body of evidence;
- Precedents (or other statements of principle) narrow down the interpretation of key concepts, so that individual decisions are more predictable; and
- Decisions are made more predictable by being derived from reliable evidence and concepts defined by precedent, since they can otherwise be challenged on appeal.

These benefits can be used to argue in favour of (1) time to consider proposals (2) consultation of interested parties and (3) reasoned decisions.

## 5.4. Conclusion

It would be strange to assume that one will find a goal more quickly when it is not clearly signposted than when it is. Flexibility about the method of reaching agreement does not necessarily promote faster resolution of disputes. On the contrary, if there are clear and agreed rules to guide decision-making, at least the method of finding a solution will not be a subject of dispute. The use of transparent regulatory procedures ensures that the highest standards of evidence and a broad consensus of opinion among stakeholders support decisions made by regulators. If regulators don't offer such transparency voluntarily, regulated companies have a responsibility to provide it themselves, where possible.

Only then will regulator and regulated company deal with one another within a long-term framework offering the "reasonable prospect of cost recovery" that ensures consumers get the services they want.

# 6. CONCLUSION

This paper sets out the high level economic principles of regulation and draws out some implications for the choice of regulatory method. The main conclusion, which is supported by influential writers, is that regulators will not enhance the efficiency of natural monopolies unless they adopt *stable and predictable* regulatory methods that offer a *reasonable prospect of cost recovery*, such that the regulated companies can *attract capital*.

To meet these criteria, regulators need methods that use objective data sources and techniques that do not require subjective decisions. A good regulatory method is one that will produce the same results with the same inputs, no matter when it is used, or by whom. In other words, the methods used at regulatory reviews should be "replicable", in that they should produce predictable results that do not depend upon the beliefs of the character of the personnel carrying out the review. In practice, all regulatory methods require an element of judgement, but the choice of method should be aimed at keeping such judgements to a minimum. This means that regulators should use information on actual costs, wherever possible, and should not rely on the forecasts of experts (who may disagree) or estimates of "efficient costs" derived from incomplete benchmarking exercises.

The need for objective methods is bolstered to the extent that regulatory decisions are subject to public discussion and appeals. Subjective methods will create disputes over assumed inputs and the associated results. Public discussion exposes such methods as, essentially, the arbitrary expression of one person's beliefs. Such criticism should, in time, lead to the adoption of more robust methods. Hence, public scrutiny of methods is essential to ensure that regulators' methods meet the criteria of "stability and predictability".

Recent changes in Europe have introduced a number of new regulatory regimes. Each such regime needs time to devise its own methods. However, no regime can overlook the need to ensure that capital remains available for efficient investment. In practice, this means that regulators should consider methods that have been successfully used to set revenues in other regimes, particularly where they have been subject to public scrutiny. It also means that regulators should avoid wasteful discussion of methods that will never meet the necessary criteria.

# APPENDIX A. X FACTORS IN THE US AND CANADA

| Sector | Company | Location | Scope | Type | Time Period | X Methodology | X-Factor |
|---|---|---|---|---|---|---|---|
| Electricity | Southern California Edison | California | T&D | Price | 1997-2001 | Costs + stretch factor | 1.2%, 1.4%, 1.6%, 1.61%, 1.61% |
| | Central Maine Power | Maine | Integrated | Price | 1995-1999 | Costs + stretch factor | 0.5%, 1%, 1.75%, 1.75%, 1.75% |
| | Bangor Hydro | Maine | Integrated | Price | 1998-2000 | Productivity | 1.20% |
| | PacifiCorp | Oregon | Distribution | Revenue | 1998-2001 | Subjectively based | 0.30% |
| | San Diego Gas & Electric | California | Distribution | Price | 2000-2002 | TFP + stretch factor | 1.32%, 1.47%, 1.62% |
| | Ontario Distribution Companies | Ontario, Canada | Distribution | Price | 2000-2002 | TFP + stretch factor | 1.50% |
| | PacifiCorp | California | T&D | Price | 1994-1999 | TFP + stretch factor | 1.4% (1994/96) 1.5% (1997/99) |
| Gas | British Columbia Gas | British Columbia, Canada | Distribution | Price | 1998-2000 | Costs | 2%, 2%, 3% |
| | Boston Gas | Massachusetts | Distribution | Price | 1996-2001 | TFP + stretch factor | 1.50% |
| | Southern California Gas | California | T&D | Revenue | 1997-2001 | Industry productivity + stretch factor | 1.1%, 1.2%, 1.3%, 1.4%, 1.5% |
| | San Diego Gas & Electric | California | G, T&D (gas and electricity) | Revenue | 1994-1999 | Growth in US non-farm economy over the past 30 years | 1.5% |

*Source: NERA compilation of data from US and Canadian regulatory decision documents.*
*"Scope": T&D = transmission and distribution, G = generation.*
*"Type": price = cap on average price or on individual tariffs, revenue = cap on total revenues.*
*"X Methodology": costs = company's own costs, TFP = total factor productivity.*
*"X-Factor": for some companies there are different x-factors for individual years during the regulatory period, while for others there is a common x-factor for the entire period.*

# APPENDIX B. PROBLEMS OF BENCHMARKING

Regulatory methods will encourage efficient expenditure and investment if they provide a reasonable prospect of cost recovery. The choice of setting tariffs on the basis of "the costs of other efficient companies", not on the basis of the costs of the company concerned have deficiencies. Many of these deficiencies arise from the fact that most of benchmarking methodologies that are currently used are too coarse to distinguish differences in cost that are the result of operating conditions and differences due to inefficiency. Benchmarking in this context will lead to arbitrary results that will not provide incentives for cost savings and will not give firms a reasonable prospect of cost recovery.

In this chapter, a description of the most popular benchmarking method "DEA" is given in section B.1. Section B.2 provides the analysis of problems with the use of benchmarking in regulation.[55]

## B.1. DEA Method

DEA is a mathematical technique for identifying a "frontier" around a number of data points. In economics, it is used to define the frontier where companies produce the most output for a given cost or, alternatively, where companies achieve the lowest cost for a given output.

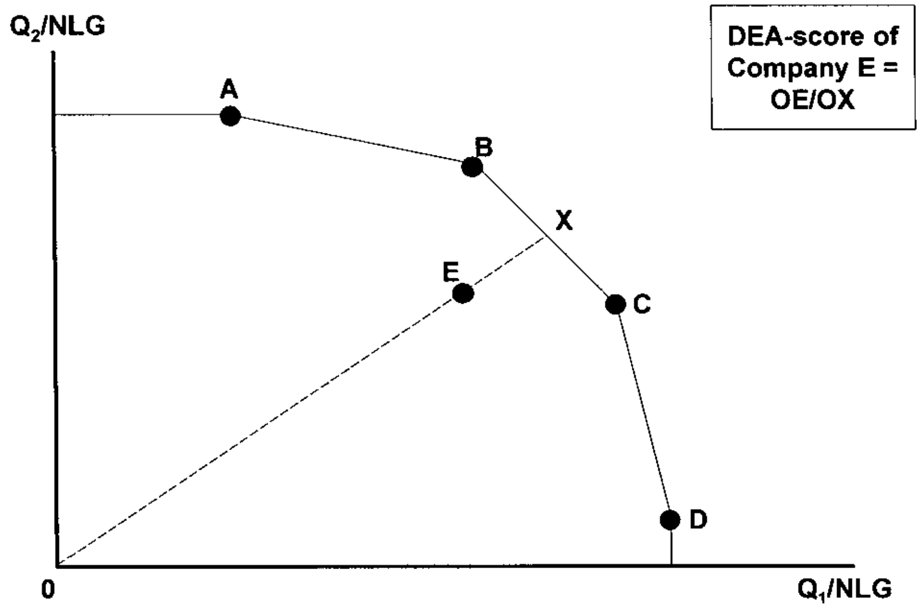
### B.1.1. The "efficient frontier"

Figure 5.1 illustrates the DEA method of defining the frontier in a two-dimensional diagrammatical example. It shows how much output five companies, labelled A to E, produce for one unit of cost, where output is defined in two dimensions: $Q_1$ and $Q_2$. This formulation is possible in cases where inputs are defined in one dimension (total cost) and where there are constant returns to scale (see below). However, DEA can be applied also to multi-dimensional inputs (eg, land, labour, capital, materials) and in conditions of variable returns to scale.

The horizontal axis in the diagram measures the amount of output $Q_1$ that each company produces per unit of cost. The vertical axis measures output $Q_2$ per cost unit. Company A, for example, produces a lot of output $Q_2$ for a given level of costs, but little of output $Q_1$. Given these output/input observations for each company, the DEA method finds an "efficient frontier" by connecting the observations for companies that lie furthest away from the origin O in the diagram.

[55] See also G.Shuttleworth, *"Regulatory Benchmarking": A Way Forward or a Dead End?* NERA Energy Regulation Brief No. 3, October 1999 (available at www.nera.com).

**Figure B.1**
**Two-Dimensional Example of DEA Benchmarking**




When there are more than two dimensions to the example (ie more outputs or inputs), the mathematical approach underlying the method remains the same, although it is more difficult to represent it simply in a diagram.

### B.1.2. DEA scores

In figure 5.1, companies A to D all lie on the efficient frontier, but company E does not. Figure 5.1 shows a DEA model that assumes all companies are comparable, regardless of their size, because the production technology exhibits "constant returns to scale". Constant returns to scale mean that, to double outputs, a company would need to double its inputs exactly. In this case, the "DEA score" measures how far company E falls short of the frontier as the ratio between distance OE and distance OX, where X is the point where a straight line through the origin O and the observation for company E meets the efficient frontier. DEA scores are measured on a scale of 0 to 1 (or 0 to 100 per cent), with companies on the frontier being awarded a score of 100 per cent.

The point X is known as a "comparator". It is a (weighted) average of other points on the frontier - in this case, of B and C. The component parts of the comparator, and their relative weights, are important for any interpretation of DEA scores.

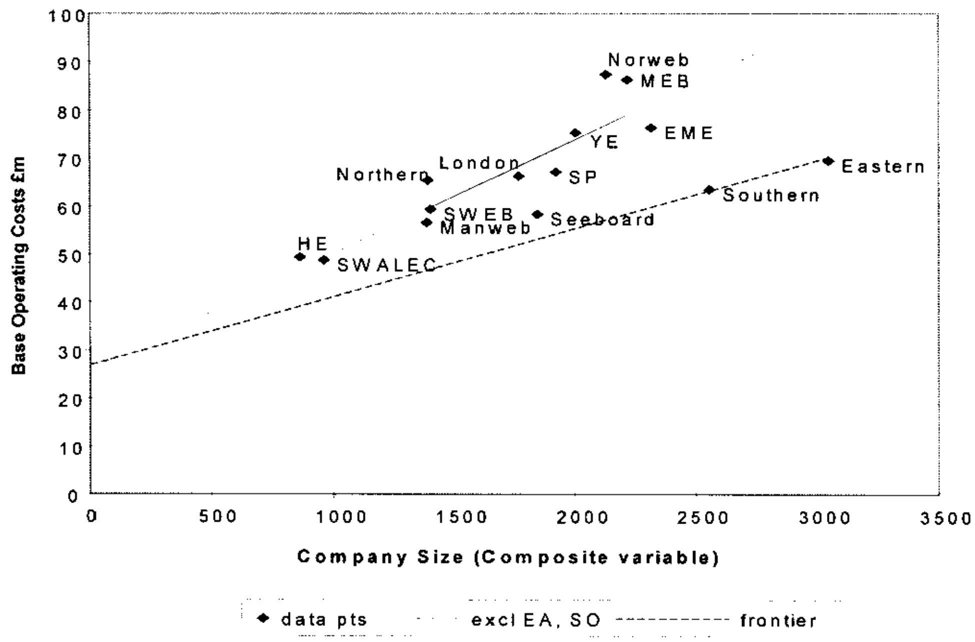
### B.1.3. Returns to scale

If the production technology exhibits variable returns to scale (VRS), it is no longer possible to represent DEA scores by the ratio of OE to OX. Variable returns to scale means that, to double the outputs, the company must increase inputs either by *more* than double (also known as decreasing returns to scale) or by *less* than double (increasing returns to scale).

Assuming variable returns to scale apply makes it impossible to show how the DEA method works in the two-dimensional output/input space used in Figure 5.1, because efficient output/input ratios vary with the size of the company. However, the basic intuition of the DEA method under VRS is the same as under CRS.

In practice, it is often difficult to disentangle returns to scale inherent in a technology from other factors linked to the size of a company. For example, in 1999, the British energy regulator, OFGEM, investigated operating expenses in the 14 British distribution businesses. Figure 5.2 reproduces a diagramme from OFGEM's draft proposals of August 1999,[56] which indicates that the smaller companies have higher "base operating costs" per unit of "size" (ie output). This observation might suggest that the sector exhibits economies of scale. However, OFGEM published its preliminary benchmarking exercise in August 1999 and then embarked in detailed discussions with each distribution company over the reasons for their deviation from the benchmark. OFGEM published an updated analysis in October 1999[57], and final revenue proposals in December 1999.[58]

**Figure B.2**
**Distribution Company Size and Operating Costs in Great Britain**




*Source: OFGEM: Review of Public Electricity Suppliers 1998 to 2000, Distribution Price Control Review, Draft Proposals, August 1999, Figure 2.1*
*Excl EA, SO = regression of data points excluding Eastern and Southern*
*Frontier = straight line through intercept of regression and data point for Eastern*

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[56] OFGEM (Aug 1999), *Review of Public Electricity Suppliers 1998 to 2000, Distribution Price Control Review, Draft Proposals*

[57] OFGEM (Oct 1999), *Review of Public Electricity Suppliers 1998 to 2000, Distribution Price Control Review, Update*

[58] OFGEM (Dec 1999), *Review of Public Electricity Suppliers 1998 to 2000, Distribution Price Control Review, Final Proposals*

During the period between August and December 1999, the distribution businesses pointed out factors that might account for their own position in the diagramme, or for the position of other companies. For instance, Eastern and Southern, the two companies with the lowest relative operating costs, also had the highest relative level of capital expenditure in recent years. Hence, in OFGEM's analysis, companies might appear less "efficient" than Eastern and Southern if their management techniques and accounting rules placed more costs under the heading of "operating expenditure", and less under the heading "capital expenditure". (Some companies had in fact opted to maintain, rather than replace, old capital equipment, and recorded higher operating costs as a result.) Also, the small companies happen to face conditions that raise costs regardless of the scale of operations, such as a more mountainous terrain or more widely dispersed customers.

OFGEM commissioned a separate efficiency audit by consultants PKF, whose investigation of the individual companies produced slightly different estimates of the scope for cost reduction. OFGEM also encouraged detailed discussion of such company-specific factors, outside the framework of this diagramme. The final proposals, issued in December 1999, did not therefore set revenues solely on the basis of the benchmarking analysis. OFGEM also took into account PKF's results, and awarded company-specific adjustments to revenues for a variety of reasons. The adjustments awarded companies higher or lower revenues, according to their particular characteristics. Small companies were not therefore systematically disadvantaged for failing to achieve economies of scale, despite the apparent results of the benchmarking exercise.

Because it is difficult to separate scale factors from other, company-specific factors, there is no universal agreement on the degree of economies of scale in electricity distribution. The treatment of economies of scale in DEA remains a matter of assumption by the practitioner.

## B.2. Problems

### B.2.1. Robustness of Methods for Calculating "Efficient Cost"

Regulators can set revenues in a way that encourages efficiency, so that the regulated company *reveals* efficient costs. However, regulators suffer an informational disadvantage, since they cannot *know* in advance what a company's efficient costs are. This problem, and its consequences, were set out by the Norwegian electricity regulatory office (NVE) in 1997, when discussing how to set price caps for electricity distribution networks:

> *"Determining which network companies are efficient and which are not is a very complicated task. In theory, NVE could differentiate the permitted rate of return according to the individual company's efficiency, as measured by NVE. The problem here is that there is no method of measuring efficiency that is generally accepted as fair, open and understandable. Defining the term efficient is especially difficult in the Norwegian electricity sector. The network companies all differ in size, structure and geographical location and surroundings. The demographic catchment areas also vary*

*greatly. A mere comparison of the companies' cost levels and cost structures will therefore often produce a misleading picture of their individual efficiency. From NVE's point of view, the problem is one of information efficiency: the network companies all have better insight into their own potential for efficiency improvements and cost reductions that NVE does."*[59]

As a result of these difficulties, NVE tried but rejected the use of DEA to set allowed revenues in 1997, and instead based the revenue allowance on actual accounting costs in 1994/95, updated for inflation, demand growth and a general productivity trend of 2 per cent per annum. NVE later chose to use DEA after all, and published new x-factors in 1999. However, no regulator has ever established a "fair, open and understandable" method of estimating efficient costs. Revenues set by benchmarking methods are not "fair, open and understandable" and do not provide useful incentives for efficient operations or investment, because they do not meet the criteria for good regulatory methods listed above (stability, predictability, credibility).

The Monopolies and Mergers Commission of the United Kingdom recognised this problem, when commenting on work undertaken for the Director General of Electricity Supply for Northern Ireland (the DG), in his review of price controls for the transmission and distribution business of Northern Ireland Electricity (NIE). Having reviewed the DG's work, and NIE's response, the MMC comments:[60]

> *"It appears to us that the application of econometric and other techniques in present circumstances has not been capable of producing useful results. There is disagreement on the most relevant cost-drivers and the appropriate scale factor (to allow for economies of scale). Moreover, the data are difficult to handle because of the wide variety of circumstances faced by companies in the sample...We are not surprised, therefore, that NIE and the DG, and their respective consultants, were unable to reach agreement on the conclusions to be drawn from the exercises that were carried out. We for our part have not found the results useful in producing reliable indications as to the relative efficiency of NIE compared with the Great Britain PESs."*

Lack of agreement over "cost drivers" and other factors make choosing a model a subjective decision, driven by unspecified criteria. Such outcomes do not provide a sound footing for regulating the return on real investments by natural monopolies.

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59 Ketil Grasto, *Incentive based regulation of electricity monopolies in Norway*, Norwegian Water Resources and Energy Administration (undated), page 3

60 Monopolies and Mergers Commission (Mar 1997), *Northern Ireland Electricity*, paragraph 2.159. In this quote, PESs stands for Public Electricity Suppliers.

### B.2.2. The Use of Reasonable Standards for the Regulatory Procedure

The direct use of benchmarking (or "efficient costs") to set revenues adopts several unreasonable standards that are biased against cost recovery.

Any estimate of efficient costs must include an allowance for the cost of capital (ie the rate of return on assets). Regulators will not encourage efficient investment if they set revenues equal to "efficient costs" including a "Weighted Average Cost of Capital" derived from estimates of normal or average rates of return in the stock market. In other sectors, companies with "efficient costs" earn *more than* the normal or average rate of return. As a consequence, this approach would offer a rate of return below the comparable rate offered by other companies. If regulated companies cannot offer investors a comparable rate of return, they will be unable to attract capital for the investment needed to maintain an efficient quality and level of service to consumers.

Furthermore, the results of benchmarking are prone to incorrect interpretation. Some regulators state repeatedly that the gap between actual costs and "efficient costs" (the frontier estimated by the model) is due to "inefficiency". In fact, such assertions are prejudicial, since the gap (or "residual") might be due to factors that were not captured in the model. In reality, a DEA score of 65 per cent (for example) does not imply that 35 per cent of the company's costs are due to inefficiency, but merely that the DEA model has failed to explain 35 per cent of the company's actual costs. DEA scores measure deficiencies in the model, as well as inefficiency in the companies.

When presented with such a "prejudicial" allegation of inefficiency, any regulated company faces an onerous burden of proof to justify its costs. To defend itself against accusations of inefficiency, a company must identify the specific factors that account for its deviation from the "frontier", ie from the level of "efficient costs" defined by other companies. This requires a detailed knowledge of other companies, and of the factors that determine their costs -- knowledge that will often be unavailable to the company concerned.

Hence, the use of benchmarking to define an "efficient" level of costs adopts a number of unreasonable standards for defining costs, interpreting DEA scores and organising the regulatory procedure. The consequence would be a systematic bias against recovery of reasonable costs and against the ability of investors to earn a reasonable rate of return.

### B.2.3. Treatment of Scale Effects

An example of an unreasonable standard of proof can be found in the final report on benchmarking produced by Frontier Economics for the Dutch energy regulator, DTe.[61]

[61] Frontier Economics, *The efficiency of the Dutch network and supply companies; final report prepared for DTe*, 1 August 2000, page 2.

Noting that large companies appear more inefficient in models that assume constant returns to scale than in models with variable returns to scale, Frontier Economics says that:

> *"...this suggests the presence of unexplained scale effects. If would simply be unacceptable for the consumers to pay for these when neither the regulator nor the company concerned can objectively justify to them why these effects exist."* (Underline added)

"Scale effects" are always difficult to explain; they may be inherent in the technology, or in differences between the conditions faced by large and small companies. Preventing a company from recovering its costs just because a consultant's model fails to explain them (and because the company cannot explain the result of the consultant's model) sets a standard of proof that few companies could meet, regardless of their efficiency.

### B.2.4. Choice of period for "Catch-up"

Although some regulators place great emphasis on the use of benchmarking to examine efficiency, a benchmark level of costs (or a DEA score) provides no basis for determining an x-factor, which is the ultimate aim of the regulator. A DEA score of, say, 65 per cent cannot be converted into an x-factor (even if one ignores the other factors that may explain costs) without specifying the *time period* allowed for the company to achieve a 35 per cent cut in costs.

**Figure B.3**
**DEA Scores Do Not Determine X-Factors Without an Assumed Catch-Up Period**

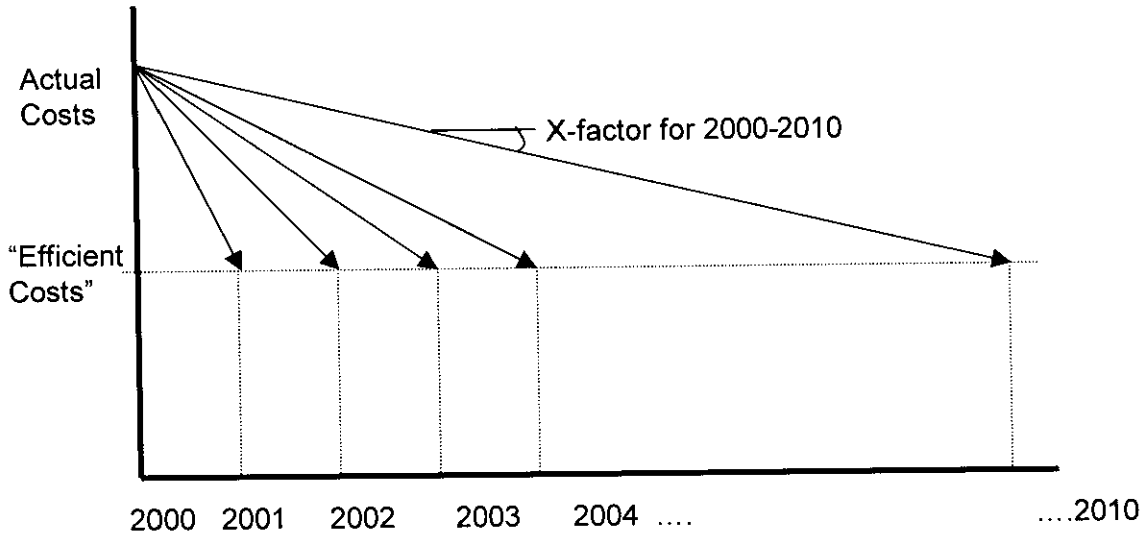


Figure B.3 illustrates the nature of the choice. Assuming that the level of "efficient costs" represents a target, the x-factor can take many different values, depending upon the date by which the company is expected to reach the target. Only by specifying an end-date, and hence the number of years allowed for catching up, is it possible to convert a percentage cut in total costs into a percentage rate of change *per annum*. Table B.1 shows the different possible values of the x-factor that a regulator might chose, depending upon the number of years allowed to move from a 65 per cent DEA score to 100 per cent.

**Table B.1**
**Conversion of 65 per cent DEA Score into X-Factor**

| Years to Catch Up | 1 | 2 | 3 | 4 | 5 | 10 |
|---|---|---|---|---|---|---|
| X-factor | 35% | 19% | 13% | 10% | 8% | 4% |

In order to decide how many years to allow for the catch-up, the regulator must first decide what rate of change in costs is reasonable. This decision must be based on evidence other than a benchmarking of cost levels. Since the x-factor is supposed to reflect a reasonable rate of change in costs, the compilation of benchmarking results has, in practice, contributed nothing to the determination of revenues.

## B.3. Conclusion

Noting these problems with benchmarking, it would be imprudent to rely heavily (let alone exclusively) on the results of benchmarking when setting x-factors. It is wrong to assert that costs remaining unexplained in a benchmarking model are due to inefficiency. Furthermore, it is unreasonable to demand that every regulated company justify its costs by reference to a benchmarking computer model.

Unless regulators investigate actual costs in detail and demonstrate that certain expenditures were inefficient by objective standards, the regulatory process will not produce allowed revenues based on a reasonable standard. Benchmarking may have a role in that process:

- inter-company comparisons can identify anomalous costs that merit further investigation;
- the companies' own decision-making procedures (eg investment planning, market testing and competitive tendering) can be benchmarked against international best practice, as a way of ensuring that the outcome is as efficient as possible;
- regulators in the US and elsewhere set x-factors on the basis of (1) observed long-term trends in productivity growth in the sector as a whole and (2) a limited stretch factor applied when the company can reasonably be expected to outperform the past.

In the last of these examples, decisions about x-factors are informed by appropriate benchmarking of cost *trends* (rates of change per annum) rather than relative cost *levels*, because comparisons of cost levels are inherently flawed.

Rede Eléctrica Nacional, S.A.

# ANEXO II

# ESTIMATION OF REN'S COST OF CAPITAL

## - A REPORT FOR REN -

# ESTIMATION OF REN´S COST OF CAPITAL

## A Report for REN

## Prepared by NERA

March 8, 2001
London

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An MMC Company

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# EXECUTIVE SUMMARY

The objective of this study is to estimate the cost of capital for Rede Eletrica Nacional ("REN") jointly owned by EDP holding (with a 30% stake) and the State of Portugal. The estimates are to be used for the forthcoming tariff review that will be undertaken by the regulatory agency, Entidade Reguladora do Sector Eléctrico (ERSE), which will set tariffs for 2002 as well as regulatory parameters for the regulatory period starting in 2002 as defined in the actual tariff code.

The focus of our study has been to estimate REN's cost of capital using a Weighted Average Cost of Capital (WACC) methodology. We have first started by reviewing REN's relative risk position, before turning to the estimation of each of the CAPM components based on international best practice. Some of our analysis is based on observed market data for EDP holding because REN has been a wholly owned subsidiary of EDP holding until recently and REN is not a publicly quoted company.

*Review of EDP's Risk Exposures*

Our analysis first considers, in a largely qualitative manner, the main risk exposures faced by the EDP holding over the next regulatory period that would impact on its cost of capital.

Our views of the risk exposure for each of the main activities undertaken by companies in the EDP group are summarised in the Table below:

**Table 1**
**Summary comparative analysis of risk by activity**

| | Generation | Transmission | Distribution |
|---|---|---|---|
| Regulatory risk | - | + | ++ |
| Cost side risk | + | - | ++ |
| Revenue risk | + | + | ++ |

As shown in this Table, we estimate that the risk for distribution activities (EDPD) is relatively higher than that for transmission activities (REN), which itself is comparable to the risk on generation activities. This is mainly due to a higher regulatory risk for distribution activities, as the form of price regulation leaves more open room for arbitrary decisions (for example, a rate of return is not explicitly allowed in the price-setting formula but must be derived backwards). This is important to inform our beta analysis, given that only EDP holding is publicly listed.

*WACC Estimates*

The following Tables present a summary of our calculations for REN. We have presented estimates of the WACC on a real and nominal basis, and pre tax and post tax basis, calculated using both Portuguese and European parameter estimates.

**Table 2**
**Calculation of the cost of capital for REN**

| | Portuguese benchmark | European benchmark |
|---|---|---|
| **CAPM parameters** | | |
| Nominal risk-free rate | 4.75% - 5.25% | 5% |
| Inflation | 2.12% | 1.76% |
| Real risk-free rate | 2.58% - 3.07% | 3.18% |
| Asset beta | 0.45 | 0.3 |
| Gearing | 42% | 42% |
| Tax rate | 38.3% | 38.3% |
| Equity beta | 0.71 | 0.48 |
| Equity risk premium | 6.0% - 7.0% | 5.0% - 6.0% |
| **Cost of equity** | | |
| Real Risk-free rate | 2.58% - 3.07% | 3.18% |
| Beta | 0.71 | 0.48 |
| Equity risk premium | 6.0% - 7.0% | 5.0% - 6.0% |
| Real Post-tax cost of equity | 6.9% - 8.1% | 5.6% - 6.0% |
| Real Pre-tax cost of equity | 11.1% - 13.1% | 9% - 9.8% |
| **Cost of debt** | | |
| Real Risk-free rate | 2.58% - 3.07% | 3.18% |
| Debt premium | 100 | 100 |
| Pre-tax cost of debt | 3.58% - 4.07% | 4.18% |
| Tax rate | 38.3% | 38.3% |
| Post-tax cost of debt | 3.58% -4.07% | 4.18% |
| **WACC calculation** | | |
| Gearing | 42% | 42% |
| Post tax WACC, gross of tax shield | 5.5% - 6.4% | 5% -5.3% |
| Post tax WACC, net of tax shield | 4.9% - 5.7% | 4.3% -4.6% |
| Pre tax WACC real | 7.9% - 9.3% | 7% - 9.4% |
| **Pre tax WACC nominal** | **10.2% - 11.6%** | **8.9% - 9.3%** |
| **Mid Point Estimates** | **10.9%** | **9.1%** |

*Comments on the Parameter Estimates*

The report considers in detail the strengths and limitations of the methodology used in the estimation. We highlight our main concerns below:

- *Risk Free Rate*: Current data on yields on government bonds suggests an estimate of the nominal risk free rate of around 5%, for both Portuguese and European markets. The spread for the Portuguese market is slightly wider than the Euro market to reflect a greater range of yields across different government securities. Market data on index linked securities is not available to estimate the real risk free rate directly. We calculate a real risk free rate based on the estimates of the nominal risk free rate adjusted for expected inflation, where inflation estimates are based on consensus forecasts.

- *Equity Risk Premium (ERP)*: Our estimates of the ERP are based on consideration of historic data on equity returns (for the Portuguese, UK, German, and US markets) and forward looking data including survey evidence and current market P/E ratios. We have also taken into consideration regulatory estimates of the ERP which range from 4-7% around the world. Based on this data, we estimate an ERP for the Portuguese market of 6.0 – 7.0%, and an ERP for the Euro market of 5.0% - 6.0%.

- *Beta:* Our estimates of beta are based on observed estimates of beta for EDP Holding, which range from 0.49 and 0.56 based on the Portuguese market index and 0.36 based on a Euro market index. This remains roughly in line with what ERSE´s advisor used at the last tariff review (0.52 for both REN and EDPD). Based on our analysis of the risks faced by the companies, we consider that EDP's distribution activities are likely to be riskier than transmission activities. We also note that recent UK regulatory decisions allow assume a higher beta for distribution rather than transmission. Based on the available evidence we estimate a beta for EDPD of 0.56 on the Portuguese market and 0.45 for the Euro market, and a beta of 0.45 for REN on the Portuguese market and 0.30 for the Euro market.

- *Tax:* To convert from a post tax WACC to a pre tax WACC we have used REN's forecasted effective tax rate for 2002 of 38.3%. We note that there are a number of different "conversion" formulas available to convert from a post tax WACC to a pre tax WACC given that there is no a priori "correct" formula we choose the most conservative alternative, ie the one yielding the lowest value for the pre-tax WACC.

- *Gearing:* For estimation of the WACC we have assumed a gearing level of 42% for both REN and EDPD based on current market gearing for EDP holding. An approach based on efficient gearing was discarded as fist, we consider that management of EDPD has not sufficient opportunity to change the capital structure of the firm since privatisation and secondly it is not clear what the efficient level of gearing for EDPD may be.

- *Debt Premium:* We estimated the debt premium for REN on the basis of current borrowing costs of EDP holding. Our estimate of EDP's debt premium for estimation of the WACC is 100 basis points. This is based on market evidence on the cost of debt of EDP holding and comparable companies.

*Comment on WACC Estimates*

Five comments can be made about the results in Tables 2 and 3:

- First, given the uncertainty about certain parameter values, our estimates of the WACC are given as range estimates. For presentational purposes we also present a mid-point estimate for EDPD for both the Euro and Portuguese markets. Expressed in nominal terms the mid point pre tax WACC estimates for REN are 10.9% and 9.1% based on the Euro and Portuguese market respectively.

- Second, expressed in post tax real terms, estimates of the WACC for REN lie in the range 5-6.4%. This compares to a recent estimate by Ofgem of a post tax real WACC of 4.8-5.2% for NGC, used for setting price controls for NGC over the period 2000-2005.

- Estimates of the pre tax nominal WACC based on the European market index are nearly 2% lower than the estimates of the pre tax nominal WACC based on the Portuguese market index. This reflects the assumption of a lower beta and lower equity risk premium for the Euro market which in part reflects the wider investment opportunity set of the Euro market.

- The choice of whether to use an estimate of the WACC based on a domestic market parameter estimates or Eurozone parameter estimates is not straightforward. The main arguments include:

  - It has historically been standard regulatory practice to estimate the WACC using parameter estimates for a domestic market. Recent UK estimates of the WACC for NGC and Electricity distribution were solely based on UK market data.

  - Estimates of the WACC based on European market data are arguably more robust than estimates of the WACC based on the Portuguese market data given the greater (current and historic) amount of information available on European stock market returns.

# 1. INTRODUCTION

The objective of this study is to estimate the cost of capital for two companies which belong to the Electricidade de Portugal S.A. group (henceforth "EDP holding"):

- Rede Eléctrica Nacional S.A. (henceforth "REN"), which is jointly owned by EDP holding (with a 30% stake) and the State of Portugal;
- EDP Distribuição (henceforth EDPD), a wholly owned subsidiary.

We have prepared this report for EDP holding. Our cost of capital estimates will be used in the debate during the forthcoming tariff review to be undertaken by the regulator, Entidade Reguladora do Sector Eléctrico (ERSE) in order to set tariffs for 2002 and the main regulatory factors throughout the next regulatory period (2002-2006).

In February this year, the ERSE published a consultation document that tackles issues of the regulatory framework in need of reform.[1] One such topic is the cost of capital, and ERSE has invited views on the best methodology for calculating the cost of capital. We note that current tariffs (as set in December 2000) use cost of capital estimates calculated on the basis of a methodology defined by an outside advisor to ERSE, (henceforth "ERSE's advisor"). This methodology, and its application by ERSE, is discussed in an Appendix to this study.

Estimates of the cost of capital are going to be used differently depending on the regulated company. For determining REN's revenues, formulas included in the "Regulamento Tarifario" (RT) include explicitly a parameter for a rate of return on net regulatory assets. Such rate of return is understood to be a pre-tax nominal WACC. By contrast, EDPD's revenue formulas do not include an explicit return for net assets (as they are defined as price cap formulas) although ERSE still assesses the impact of the tariffs it sets on EDPD's allowed rate of return. The rate of return calculated in this context should be understood as a post-tax nominal WACC.

In this report, we have applied "best practice" methodology to estimate the cost of capital for each of these companies and have based our estimation on their Weighted Average Cost of Capital (WACC). Our methodology provides elements of answer to the questions raised in ERSE's consultation document.

## 1.1. Methodology

We have conducted a qualitative analysis of the different risks inherent to EDPD's and REN's business environment (see Appendix). Second, we have gathered elements for calculating the WACC of REN and EDPD using international best practice.

1 ERSE (2001) "Revisão dos Regulamentos do Sector Eléctrico- Documento de Discussão", 12 February 2001.

The cost of equity was calculated using the Capital Asset Pricing Model (CAPM) given that, despite its limitations it is the most widely used model for the calculation of the cost of equity in regulated industries both by regulator's and practitioners. We have attempted to achieve a robust estimation by

- Working with range estimates rather than specific point values;
- Drawing data from alternative sources and a broad range of European comparators;
- Making use of alternative estimation procedures whenever possible.

## 1.2. Structure of this Report

The rest of this Report is structured as follows:

- *Section 2* summarises the main principles guiding our methodology for estimating the cost of capital for each of these companies;
- *Section 3* presents our estimation of the cost of equity for each of the companies;
- *Section 4* presents our estimation of the cost of debt for each of the companies;
- *Section 5* summarises our findings and contains estimated values for the cost of capital;
- *Appendix A* analyses in a critical manner the methodology used for setting current tariffs (i.e. Outside advisor's estimation as applied by ERSE);
- *Appendix B* presents the operating environment for each of the companies in order to estimate their relative riskiness;
- *Appendix C* presents the criteria for choosing comparator companies for both EDPD and REN and background information on these comparator companies.

# 2. PRINCIPLES FOR CALCULATING THE COST OF CAPITAL

In this Section, we review the principles underlying our cost of capital calculation and we highlight the main choices that need to be made in order to reach an agreement at the level of principles. We start by reviewing issues with the general methodology and then turn to methodological issues affecting specific components, i.e. estimating the cost of equity and the cost of debt and their aggregation using the gearing ratio.

## 2.1. General Methodology

The Weighted Average Cost of Capital (WACC) methodology, as defined below, is now widely accepted in European markets as a suitable method for calculating the cost of capital. The generic formula used for calculating a pre-tax WACC is as follows:

$$\text{Pre-tax WACC} = r_E \,.\, (1\text{-}g) \,.\, t_{adj} + r_D \,.\, g \qquad (1)$$

*where:*

- $g$ = gearing = debt/(debt + equity)
- $t_{adj}$ is the tax adjustment factor used to convert the post-tax cost of equity to a pre-tax figure. As interest on debt is not taxed, this is applied to $r_e$ only.
- $r_e$ = return on equity = risk free rate + beta x equity premium
- $r_d$ = return on debt = risk free rate + debt premium.

The WACC formula reflects the fact that companies can raise capital through either debt or equity and that the returns required by the market for each of these two elements are likely to be different. The true cost of capital for a company is a weighted average of the two.

The corresponding expressions for the "post-tax" WACC is given by:

$$\text{Post-tax } WACC_{grross-of-tax-shield} = r_E * (1-g) + r_D * g \qquad (2)$$

Note that the cost of debt component is identical both pre and post-tax (which reflects the fact that interest payments are considered expenditures and not taxed while return to shareholders is driven by profits which are taxed). Sometimes an alternative post-tax formula (net-of-tax-shield) is used

$$\text{Post-tax } WACC_{net-of-tax-shield} = r_E * (1-g) + *(1-t) * r_D * g \qquad (2)$$

Where t is the corporate tax rate. However, the revenue that must be allowed to a regulated firm on top of its tax liabilities so that this firm can meet its cost of capital is given by the post-tax WACC times the regulatory asset base. In this sense the post-tax WACC gross-of-tax-shield is more informative in a regulated context (both results are reported in our calculations).

*Capital contributions*

In a recent consultation document[2] ERSE has asked whether it is appropriate to use the following formula for calculating the WACC for both REN and EDPD:

$$WACC = r_E * \frac{E}{E+D+S} + r_D * \frac{D}{E+D+S} + r_S * \frac{S}{E+D+S} \quad (3)$$

Where $S$ represents capital contributions[3] and $r_S$ is set to zero.

This was the WACC formula used by ERSE´s advisor to calculate REN's and EDPD's cost of capital.[4] We consider this approach to dealing with capital contributions to be confusing, and not in line with international best practice.

When a distribution or a transmission company incurs a cost that is directly attributable to a customer (for instance, for assets directly involved connecting a customer to the grid), this cost is usually borne by the customer. This is referred to as a capital contribution or customer "subsidy". Portuguese electricity companies are not unique in receiving this kind of contributions: in the UK, both NGC and the RECs receive capital contributions. Capital contributions should not be included in the asset base for regulatory purposes, i.e. they should not incur depreciation costs or earn a rate of return.[5] This is the case in the Portuguese system where ERSE in its application of the RT allows a return on REN's assets *net* of capital contributions. The return on EDPD´s assets is not explicitly included in the revenue formulas of the RT but when ERSE determines revenues it is reasonable to assume that it only considers a return on EDPD´s assets net of customer contributions. Alternatively ERSE could apply the WACC given by (3) on *all* of the company´s assets, however this approach seems unnecessarily complex. ***It should be noted that applying a WACC derived from (3) to a company´s assets net of contributions is incorrect and would lead to underecovery of the firm´s capital costs.***

Thus our approach to calculating the WACC of REN and EDPD will be to use the standard WACC expression, without including a term for capital contributions. This is in accordance with international best practice and it is the approach that is followed by regulators and practitioners in the UK, Netherlands, and Italy, among others.[6]

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2 ERSE (2001) Revisao. Op. cit.

3 Capital contributions account for approximately 25% of EDPD's net fixed assets.

4 See Appendix A below.

5 In the case of NGC and the RECs in the UK, customer contributions appear twice on the companies assets account: once as a positive entry just as any other asset and a second time as a liability under a heading usually referred two as customer grants. Furthermore the grants entry is depreciated and produces negative yearly depreciations that ensure that customer contributions do not incur a depreciation cost.

6 REFS for NGC (2001), PES (2000), Dte , and Autorita per l'energia electrica e il gas (1999)

*Use of local vs. international market benchmarks*

It is common practice to estimate several of the parameters in the cost of capital calculation with respect to the local market in which the companies operate. For example, betas are usually defined as the statistical relationship between equity returns on the company under consideration and the market in which it is traded. The implicit assumption behind this is that investors only diversify their investments within the local stock market.

However, with the introduction of the Electricity Directive and a general trend towards market internationalisation, the electricity market is increasingly becoming an international one, at least at the European level. This means that, in practice, investors are not limited to the local stock market but they can invest in any stock market around the world.

It is therefore important to estimate the cost of capital components with respect to the European market, if not to the international market. This applies to several of the parameters in the cost of capital calculation and so, where applicable, we calculate the cost of capital on the basis of both a national and European-wide benchmark.

## 2.2. Cost of Equity

The post-tax cost of equity is the return on equities (through dividends and through an increase in the value of shares) that is required to attract investors. There are essentially two ways of calculating the cost of equity: the Capital Asset Pricing Model (CAPM) and the Dividend Growth Model. Below, we review the pros and cons of each of these methodologies in turn.

### 2.2.1. Capital Asset Pricing Model (CAPM)

#### 2.2.1.1. *General principles*

The CAPM model estimates the required post (corporate) tax returns on the equity of a company in the following way:

$$E[r_e] = E[r_f] + \beta(E[r_m] - E[r_f])$$

*where,*

$E[r_e]$ is the expected return on equity
$E[r_f]$ is the expected return on a risk-free asset
$E[r_m]$ is the expected rate of return for the market; and,
$\beta$ is a measure of the systematic riskiness of the asset.

2.2.1.2. *Beta*

An important aspect of the CAPM model is the underlying assumption that people can diversify their investment portfolio through purchasing other assets. The risk associated with an equity in the CAPM model (captured through the value of $\beta$) reflects the non-diversifiable risk of that equity. It is therefore a measure of the strength of the relationship between the expected returns on an asset and the expected returns on a broad portfolio of assets. If the assumptions of the OLS technique are met by the data, the slope coefficient is a "best-fit" unbiased estimate of the equity beta.

In theory, a full range of assets are available to investors and returns to all assets should be included in the model. However, in practice, the returns to the stock market are used in the calculation as a proxy for the returns to all assets. We have discussed above whether only national or also international stocks should be included in the estimation of general market returns.

Formally, beta is defined in the following way:

$$\beta = \frac{\text{cov}(r_e, r_m)}{\text{var}(r_m)}$$

*where;*

$r_e$ is the return on a specific stock

$r_m$ is the return on the market as a whole

***Estimation period***

In practice, forward looking estimates of returns on particular stocks and on the market as a whole are not readily available therefore we use historic returns as a proxy for expectations about the future.

However, using historic returns to estimate future values of beta raises the question of which is the correct period to use in the sample. It is argued that, since we are using historical data as a proxy for forward-looking expectations, we should choose the most recent period possible, since this will embody market expectations about future returns. This would lead us to look at, for example, daily data over the past one or two years.

It is also argued that the values of beta fluctuate systematically over the business cycle. Therefore taking only a recent period (i.e. less than one complete business cycle) risks missing information and biasing the results. According to this argument, betas should be calculated over as long a period as possible to smooth out the effects of long-run cycles.

There are some very practical considerations with respect to the choice of periodicity of data collection. In order to generate a statistically significant estimate of the value of beta, it is important to have a data set of a reasonable size. If the estimate of beta is based on recent historical data, then daily or weekly data is required in order to provide a sufficiently large sample size. However, if the value of beta is to be estimated over a longer period, then monthly data is sufficient. The disadvantage of daily data is that it can introduce a variety of biases associated with thin trading, serial correlation of market returns and asynchronous price adjustment processes. Studies have shown that infrequently traded securities are likely to be biased downwards for these reasons.

***Business risk and financial risk***

The equity or 'levered' betas are calculated on the basis of the relationship between the stock price of the companies and the local stock market as a whole, and thus the value of the equity beta reflects two types of risks:

- Business risk: As the level of business risk increases, profit streams become more sensitive to changes in general economic conditions and hence company returns become more highly correlated with market returns.
- Financial risk: As the gearing ratio (D/(D+E)) rises and the company issues more debt, the fixed interest costs on debt increases, meaning that profit streams also become more volatile and leads to a rise in the beta estimate.

In order to be able to compare levels of business risk across companies, it is necessary to calculate the asset or 'unlevered' beta of the company. The unlevered beta of the company is defined as the value of beta for the company on the assumption that the company holds no debt. Standard formulae are normally used to adjust the unlevered beta for the level of gearing of the company.

In the CAPM framework, the traditional way to account for the impact of a change in gearing on the cost of equity is to adjust the beta coefficient in a linear manner, reflecting the fact that the variability of equity returns is directly proportional to the amount of profits paid out as interest payments. To go from unlevered (or asset) betas to levered (or equity) betas, the following formula is used:

$$\beta_{equity} = \beta_{unlevered}\,(1+(1-T)*(Debt/Equity))$$

*where* T is equal to the effective tax rate.

As a company's gearing increases, the variability of equity returns increases, since debt represents a fixed prior claim on a company's operating cashflows. For this reason, increased gearing leads to a higher cost of equity, reflected in a company's beta value.

In the event that a company is expected to increase its level of gearing in the future, it is necessary to adjust the observed equity beta for the higher level of financial risk that will result form the higher gearing. In practice this is done by first calculating an unlevered beta based on the current (and historic) gearing levels and then lever the beta for the higher (or expected) future gearing levels. It is important to emphasise that the value of beta needs to be consistent with the assumed level of gearing, in order that equity holders are rewarded for the levels of financial risk to which they are exposed.

***Estimating Betas for Non-Quoted Companies***

We describe below two methods of estimating a company's beta: the "earnings" beta and the "pure-play" beta.

*Earnings beta*

Since beta measures the relationship between an individual company's returns and market returns, and since the relationship is determined by the correlation between a company's earnings and overall corporate earnings, we can compute an "earnings beta". A time series of a company's quarterly earnings for each of the activities can be regressed on the corresponding index of aggregate quarterly corporate earnings. The slope coefficient of the regression is the earnings beta. Since stock prices respond to earnings, the earnings beta and the stock beta should be highly correlated. Why is this method not used?

*Pure-play beta*

This method attempts to identify publicly traded companies whose operations match those of the unquoted company in question. Having identified a sample of "comparator" companies, the sample's average beta serves as a substitute for the non-traded company's beta. In employing this approach, regulators may attempt to account for differences between the comparators and the company in question by making subjective adjustments to beta. The outcome is typically a relatively broad range of values for beta.

One drawback to this method is that although the proxy companies may have the same business risk as the unquoted company, they may have different capital structures. Because observed beta reflects both business and financial risk, betas of companies with different financial structures are not directly comparable. To account for these differences, it may be necessary to consider the leverage of the respective firms.

2.2.1.3. *Risk-free rate*

The expected return on a risk-free asset ($E[r_f]$) or the "risk-free rate" is the return on an asset which bears no risk at all. Formally, the real risk free interest rate is the price that investors charge to exchange certain current consumption for certain future consumption. In part, it is determined by investors' subjective preferences and in part by the nature and availability of investment opportunities in the economy.

Financial theory says that the true risk free rate is one that has zero correlation with the market portfolio ie, a return on a zero beta asset or portfolio. In practice, however, there are few good proxies for a risk free asset since inflation and other factors has been shown to lead to covariance between bond and stock markets (Harrington (1987)). In an important review of the principles of CAPM application in UK regulation, Holmans (para 2.5.3) states that there is no satisfactory proxy for the risk free rate. This same problem is well documented in US applications of the CAPM (see Harrington (1987)).

In the UK, the best proxy for the risk free rate is generally considered to be the return on index linked gilts. The reason for this is twofold. First, the yield on index-linked gilts is immune from the effects of unanticipated inflation and represents an estimate of the forward looking return that investors currently require. Second, it has been argued that the returns on index linked gilts are less correlated with the market than the returns on Treasury bills and other government bonds, and are therefore closer to satisfying the theoretical requirement of having a zero beta.[7]

However, in many countries, index-linked sovereign bonds are not issued or not traded in sufficient quantities. If the government issues nominal government bonds, these can be used as the risk-free rate but they need to be adjusted for the risk of unanticipated inflation.

### 2.2.2. Dividend Growth Model (DGM)

The Dividend Growth Model approach rests on the assumption that the value of an asset relies on the future cash flows it will generate. When applied to share valuation, the future dividends are the expected cash flows. The cost of capital is specified as the rate of return that equates the market price of a share with the present value of the cash flows investors expect from a share.

The normal model that is used is based on the assumption that expected future dividends follow a constant future growth path. This model, known as the "simple DGM", estimates the cost of equity as:

$$r_e = D_1/P_0 + g$$

which states that the cost of equity ($r_e$) is equal to the sum of the expected dividend yield ($D_1/P_0$) at the time of purchase and the expected growth rate of dividends (g) into the future.

To estimate dividends, two approaches can be taken:

- Analysis of historical growth rates of dividends of the company;

[7] This point was made by Stephanie Holmans in Ofwat RP5 (1996), Section 2.5.

- Analysis of market evidence such as analysts' expectations, or by expectations about future growth in the general economy.

The difficulty if we were to apply the DGM to estimate the cost of equity for European electricity companies is that, in view of the dynamically changing market, there is a very great degree of uncertainty over the value for the expected growth rate of dividends. Analyst forecasts of future dividend streams also rarely extend beyond two to three years. In view of the dynamically changing market future dividend streams are unlikely to be constant. In addition, for new entrants, dividends may be expected to be very low in the early years of operations and then grow at faster rates as the company and the market "matures". But there is a great deal of uncertainty about this time path meaning that any attempt to apply the DGM will lead to large range of estimates for the cost of equity.

Besides, historical growth rates of dividends are unlikely to be a realistic representation of future dividends for European electricity companies.

Analyst expectations of dividend growth rates expectations will depend to a large degree on what the analysts view of the likely outcome of a price review. There is hence a large degree of circularity in using the DGM in determining the cost of capital to be used in a price review for a regulated company.

In view of these difficulties we have not sought to apply the DGM to estimate the cost of capital for EDPD and REN in this study.

## 2.3. Principles for Estimating the Cost of Debt

The cost of debt can be expressed as the sum of the risk free rate and the company specific debt premium. The company specific debt premium is driven by the ratings that specialist credit rating agencies, such as Standard & Poor's (S&P's), assign to that company.[8]

In essence, credit ratings are based on a number of financial characteristics such as market capitalisation, earnings volatility, and business risks specific to the company and/or the sector. However, particular regard is paid to the following two financial ratios:

- Funds From Operations (FFO) interest coverage; and
- Interest Coverage defined on earnings basis (where the earnings considered are before interest and taxes, EBIT).

Interest cover, defined as the number of times by which a company can meet its interest payments out of operating profits, is essentially a measure of the surety of interest payments

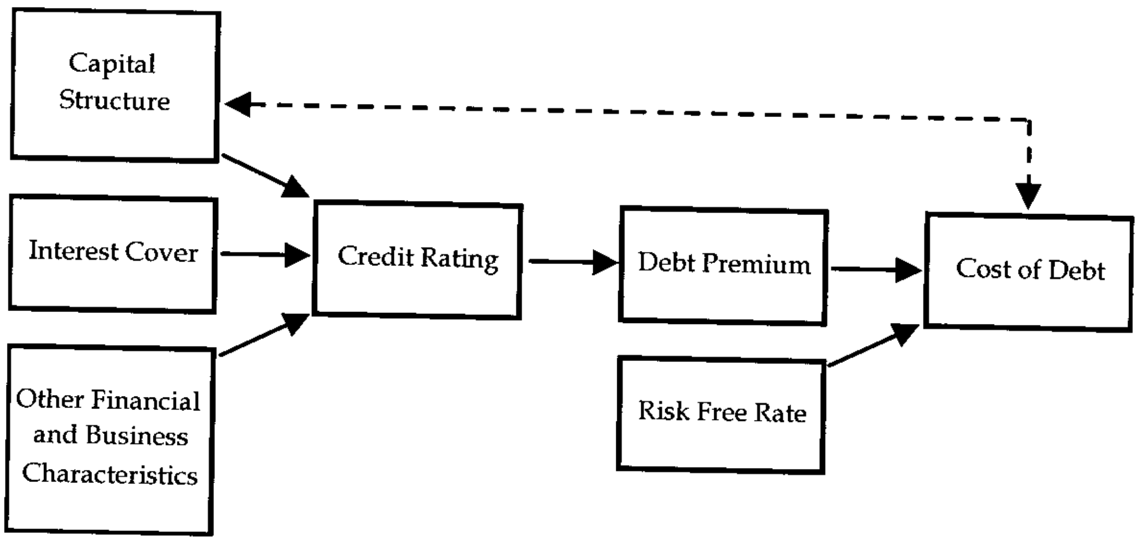
[8] Some companies, particularly large and well known, choose not to be rated but still access the capital markets for debt at appropriate levels.

being met. A company with low interest cover is less likely to maintain a premium credit rating, since the probability of default on interest payments will be relatively high. S&P's particularly emphasises funds flow interest coverage as a rating criterion.

A company with a high gearing ratio is also less likely to maintain a premium credit rating. This reflects the fact that the probability of default on interest payments will be higher if gearing is high. It is clear that credit rating agencies, in determining credit ratings, are concerned primarily not with capital structure per se, but rather with debt service coverage levels, measured on both a cash flow and earnings basis. [Relationships between gearing and interest coverage will differ across companies according to the specific finance arrangements.]

Figure 2.1 summarises the postulated relationships between gearing and interest cover, credit ratings, other business and financial characteristics and the debt premium and cost of debt.

**Figure 2.1**
**Relationship Between Capital Structure, Interest Cover, Credit Rating and Cost of Debt**




## 2.4. Principles for Estimating Gearing

Finance theory says that the appropriate discount rate for expected future cash flows is the Weighted Average Cost of Capital (WACC) that represents a weighted average of the expected costs of debt, equity and hybrid financing.

It is now generally accepted that changes in the proportion of debt and equity in the balance sheet can, in practice, have significant implications on a company's overall costs of finance. This is the result of a number of factors that occur when gearing is changed:

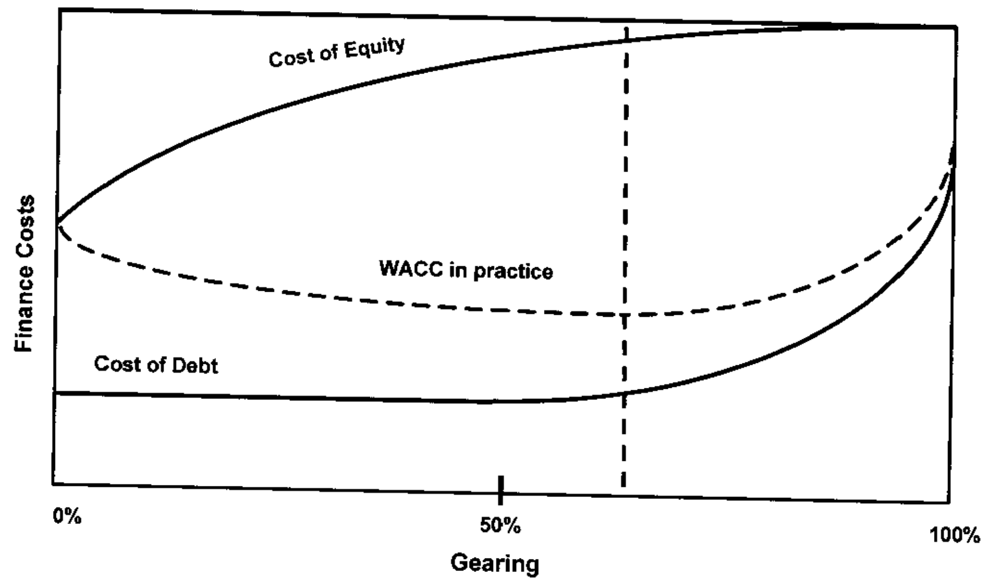
- Debt risk and interest rate changes;

- Equity risk changes;
- Probability of future default changes;
- Tax position (personal and corporate) changes;
- Investment strategy may change.

Academic theory cannot predict what proportion of overall finance should be raised through debt or equity. In general terms, debt is advantageous because of its low costs and tax deductibility but can be disadvantageous where personal taxes and bankruptcy costs are concerned. The optimal capital structure of a company will normally consist of a mixture of debt and equity finance.

Companies with stable cash flows and low risk profiles can absorb more debt into their balance sheets than most other types of companies. However, to assess the optimal capital structure of a utility, an empirical analysis is required that examines market evidence on how the perceptions of investors, credit rating agencies and financial markets in general are affected by capital structure changes.

**Figure 2.2**
**Does Capital Structure Matter?**




In assessing "optimal" capital structure it is important to focus not only on central case scenarios but also on downside scenarios. The possibility, for example, that capital expenditure may be substantially above central case projections may mean that an "optimal" capital structure will allow for unused borrowing capacity to increase debt in adverse circumstances. Some trade-off is likely to exist between minimising the average cost of new finance and minimising the *possibility* of financial distress and bankruptcy.

# 3. ESTIMATING THE COST OF EQUITY

## 3.1. Risk-free Rate

The risk-free rate is a measure of expectations about future returns on a risk-free asset. In theory this is captured by the current yields on benchmark government bonds, as current rates would best capture expectations about future returns. In countries where index-linked bonds exist (i.e. they are inflation-adjusted) these can be used as an estimator of the real risk free rate. However, these do not exist in Portugal, which is why we also need to make estimates for future inflation in order to derive a real rate (see Section 3.2. below).

### 3.1.1. Issues to be considered

In determining the relevant rate to use for the risk-free rate, there are a number of issues to consider. We review each of these questions below.

*Maturity*

The correct type of bond to use as the risk-free rate is a subject that generates a considerable amount of debate in other countries when determining the cost of capital. From a theoretical point of view, the time horizon considered could either reflect the life of the relevant regulated assets or the regulatory review period (usually around 5 years).

Since it is often not possible to reach agreement on this issue, yields on medium and long-term bonds are often used as limits for the value of the risk-free rate. However, increasingly regulators around the world tend to use 10-year bonds. The main reason underlying this choice is that the 10-year bond is typically the security that has the closest maturity to the 15 year plus investment profile of utility assets whilst also maintaining a certain liquidity and market depth. On the other hand, one may look at a combination of the longer-year bonds in order to provide some recognition of the useful life of the assets as well as the investment profile of investing in electricity assets. However There is no 'correct' maturity to use when estimating the risk free rate to be used in the CAPM.

*Current yield vs. average yields*

Economic theory says that the current yield on bonds reflects the market's expectations about the future therefore this is theoretically the best measure for CAPM.

However, there is also evidence that yields show random fluctuations over time due to, amongst other things, thin trading and temporary market conditions. A long-period average avoids this problem and is sometimes a better predictor of future yields than the current yield.

This being said, a historical average would also pick up the effects of abnormal periods and it is possible that this provides a misleading estimate of future values. A simple test of checking whether the current yields should be considered as 'abnormal' is to compare current with historic rates.

### 3.1.2. Review of available evidence

As mentioned in Section 2.1., we are estimating the cost of capital both on a local market index and an international market index. Below, we present evidence on bonds available for estimating the Portuguese risk free rate and also some broader European evidence. We note that, for the previous tariff study, ERSE's advisor assumed a risk free-rate of 4% based on an average of various Portuguese bonds.

*Portuguese benchmarks*

Following the EU accession, the Portuguese financial markets were liberalised and new instruments were introduced in the bond and equity markets, leading to the development of a relatively liquid market.

A new 10-year benchmark issue was introduced in January 2000 with an initial offering of EUR2.5 billion. Government bonds are the *Obrigações de Tesouro (OTs)*, and benchmarks exist for the 3-, 5- and 10-year maturities. They are listed in Table 3.1 below, which shows the current returns on the Benchmark bond compared to their average yields for the period 1999-2001.

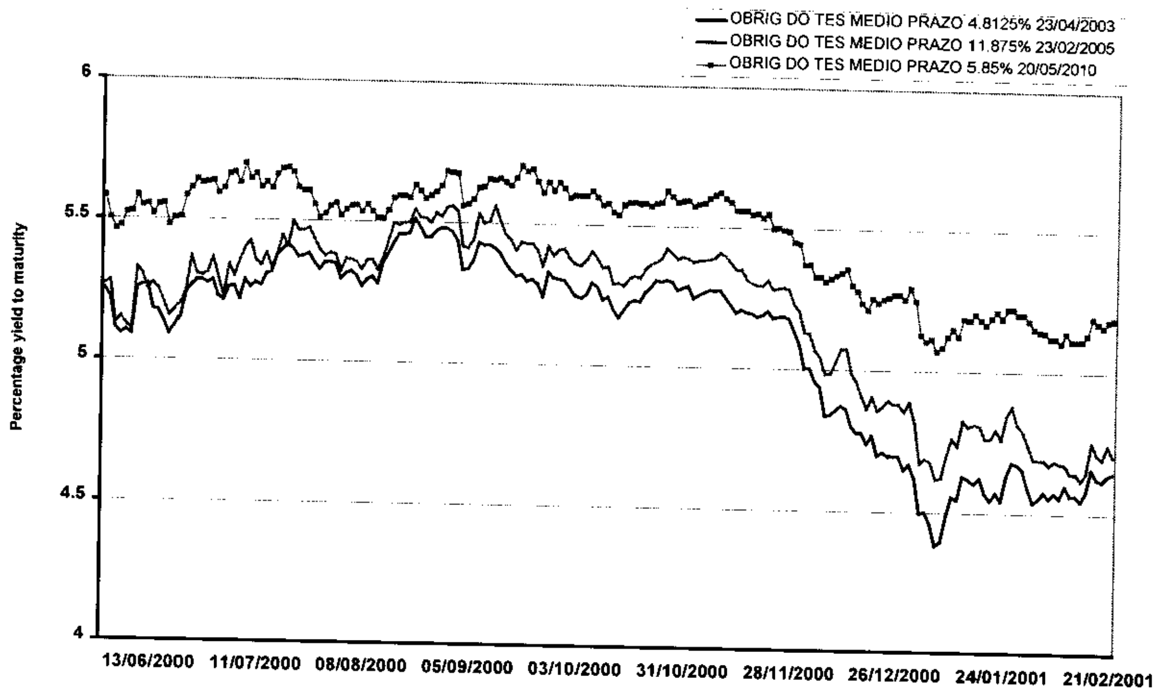
**Table 3.1**
**Portuguese Benchmark Bonds**

| Bond title | Coupon | Maturity date | Current yield to maturity[1] | Average yield to maturity[2] | Yield at 30/6/2000 |
|---|---|---|---|---|---|
| Oblig. do Tes. medio prazo | 4.8125% | 23/06/2003 | 4.617% | 4.600% | 5.14% |
| Oblig. do Tes. medio prazo | 11.875% | 23/02/2005 | 4.705% | 4.717% | 5.227% |
| Oblig. do Tes. medio prazo | 5.85% | 20/05/2010 | 5.189% | 5.543% | 5.611% |

*Source: NERA analysis of Bloomberg data. 1: As at 21/02/01. 2: Average over 21/02/99 to 02/02/01.*

The current yields on the short maturity bonds are approximately in line with historical averages, whereas the difference is greater on the longer-term bond. A comparison with the yields half a year ago shows that these have fallen by about 0.5% over this period, as shown in the Figure 3.1. below.

**Figure 3.1**
**Historical yield to maturity of Portuguese Benchmark Bonds over the last 6 months**




Such fall is observed in other European markets, as explained below.

*European risk-free rate*

In the Euro area bond market, the yields remained within a fairly narrow band earlier during the year in 2000, following indications of slightly slower growth and relatively muted inflationary pressure. Subsequently, however, the perception that the US economy was undergoing a sharper slowdown than earlier anticipated, combined with portfolio inflows into bonds arising from stock market volatility, caused US bonds yields to fall quite markedly in early December and had spill-over effects on euro area bond markets. Table 3.2. below shows a selection of bonds issued by three European governments, and compares the current yield with the average over the past year, as well as the yield half a year ago. The results indicate that the average of the bonds over the last year are significantly higher than what is currently observed, and are driven by the higher yields earlier during the year. Therefore, it is more appropriate to take current rates as a proxy for expected risk-free rate.

**Table 3.2**
**European bond yields**

| Country | Bond type | Current yield to maturity | Average yield over last year[2] | Yield at 30/6/00 |
|---|---|---|---|---|
| Germany | Bundesschatzanweisungen 4% 14/12/2001 | 4.519% | 4.812% | 4.959% |
| Germany | Bundesobligation 5.25% 18/02/2005 | 4.494% | 4.964% | 5.051% |
| Germany | Bundesrepub. Deutscheland 5.375% 04/01/2010 | 4.725% | 5.165% | 5.228% |
| Germany | Bundesrepub. Deutscheland 6% 20/06/2016 | 4.982% | 5.282% | 5.297% |
| | | | | |
| France | Trésor 5% 20/02/2001 | 4.493% | 4.879 | n.a. |
| France | Trésor 6.5% 25/10/2006 | 4.669% | 4.783% | 5.179% |
| France | France (Gouvernement) 5.5% 12/09/2000 | 4.968% | 5.164% | n.a. |
| France | France (Gouvernement) 8.5% 25/10/2019 | 5.343% | 5.475% | 5.601% |
| | | | | |
| Italy | Buoni Polienniali del Tes 4.5% 15/01/2003 | 4.562% | 5.085% | 5.276% |
| Italy | Buoni Polienniali del Tes 9.5% 01/02/2006 | 4.842% | 5.360% | 5.502% |
| Italy | Buoni Polienniali del Tes 5.5% 01/11/2010 | 5.174% | 5.500% | 5.574% |
| | | | | |
| Spain | Bonos 10.10% 28/02/2001 | 4.711% | 4.096% | 4.836% |
| Spain | Bonos 10.15% 31/01/2006 | 4.85% | 4.952% | 5.374% |
| Spain | Bonos 8.20% 28/02/2009 | 5.095% | 5.187% | 5.497% |
| | | | | |
| **Average of short term bonds (< 5 years)** | | | | |
| **Average of long term bonds (> 10 years)** | | | | |

*Source: NERA analysis of Bloomberg data. 2: Average over 22/02/99 to 21/02/01.*

Furthermore, in the most recent Monthly Bulletin published by the European Central Bank[9], shows that the average 7-year maturity government bond in the Euro area has a yield of 4.97%, whereas the 10-year bond has yield of 5.06%.

### 3.1.3. Summary

For the nominal risk-free rate estimated in the Portuguese market, we would be inclined to use a range comprise between 4.75% and 5.25%, which encapsulates the range based on various bond maturities and the recent fall in yields (we would put a stronger emphasis on current rates, as they are a better representation of future market expectations). Based on the above data our best estimate of the nominal Euro risk-free rate is 5%.

[9] Monthly Bulletin, February 2001, p25

## 3.2. Inflation

As we have chosen a risk-free rate based on bond yields that extend up to 10 years, we can estimate the real risk free rate by using inflation forecasts over a similar period. In the Table below, we show the inflation forecasts from OECD "Consensus Forecasts Global Outlook 2000 – 2010" for the period 2000 to 2010.

**Table 3.3**
**Inflation forecasts**

| Country | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 - 2010 |
|---|---|---|---|---|---|---|---|
| Portugal | 2.6 | 2.7 | 2.5 | 2.3 | 2.0 | 2.0 | 1.8 |
| Eurozone | 2.2 | 2.0 | 1.8 | 1.7 | 1.8 | 1.8 | 1.7 |

*Source: Consensus Forecasts Global Outlook 2000 – 2010.*

Given these figures, the average over the 10 years (2001 to 2010) is 2.12% for Portugal, and 1.76% for the European Union. Each of these figures will be used as the expected level of inflation the Portuguese and the Europe scenario respectively.

## 3.3. Equity Risk Premium (ERP)

The equity risk premium or ERP is the difference between the expected return on the market portfolio and the expected return on the riskless asset, formally stated as $E(r_m)$ - $E(r_f)$. Determining a value for the equity risk premium has caused substantial controversy in application of the CAPM, both in UK regulatory settings and elsewhere.[10]

A number of different approaches can be used to estimate the ERP, which can be broadly stated as:

- *Ex-post approach*: Calculation of average differences between *realised* returns on a proxy for the market portfolio and *realised* returns on proxies for the risk free asset. It is assumed with this approach that the expected premium is constant over time and that realised premiums converge towards this expectation when averaged over sufficiently long periods (ie. there is no systematic bias between expectations and outturns).

- *Semi ex-ante approach*: Calculation of average differences between *realised* returns on a proxy for the market portfolio and observable current (or recent) expected yields on proxies for the risk free asset. It is assumed with this approach that equity

[10] As Jenkinson (1998) says: "*The controversies involve whether to use purely historical data to project future expected returns, what method of averaging should be used, whether the risk premium is constant over time, and what is the relevant time horizon of investors.*"

returns in the market are constant over time (rather than the equity risk premium). In other words, it assumes that there is no relationship in practice between the risk free rate and market returns.

- *Ex-ante approach*: Calculation of average differences between observable (eg, survey of investors) *expected* returns on a proxy for the market portfolio and observable current (or recent) *expected* yields on proxies for the risk free asset. Sometimes, averages of expectations over some historical period are used, modified for changes in economic circumstances.

Each of these methods is discussed in the following sections.

### 3.3.1. Ex-Post Approach

As stated above, estimating the ex post approach estimates the ERP using the average differences between *realised* returns on a proxy for the market portfolio and *realised* returns on proxies for the risk free asset.

Estimates of the ERP derived using an ex post approach are sensitive to the following factors:

- Choice of historic time period.
- Choice of market.
- Choice of index.
- Choice of risk free rate.
- Choice of averaging period.

***Choice of Historic Time Period***

There is no right time period to use when analysing historic data to estimate the ERP.

Using long term historic averages is most likely to overcome the possibility of systematic bias between expectations and outturns. Long term averages of returns are most appropriate if it is assumed that the equity risk premium is constant over the measurement period and will remain constant in the future.

A number of recent studies have shown that there are good theoretical and empirical reasons why the equity risk premium may change over time, and are specifically correlated with changes in interest rates, inflation, the business cycle, and pension fund weightings. This was noted by Cooper (1995), is discussed by Engel and Morris (1991), Blanchard (1993) and, more recently, by Wadhwani (1999) in the NIER.

In this study we consider estimates of the ERP based on historic data over 10-30 years.

*Choice of Market*

In this study estimates of equity risk premia are derived for both the Portuguese market and the Euro Zone market.

*Choice of Index*

We have used a broad domestic stock-market index as a proxy for all available assets - Portuguese PSI20 index for the equity premium on the domestic market. This is a capitalisation-weighted index of the top 20 stocks listed in the Lisbon Stock Exchange, and was developed on 31 December 1992. A conceptual problem with the use of this index, which applies equally to other economies where equity markets represent a small proportion of the overall economy, is that a selection of 20 stocks is unlikely to be representative of the true investment opportunity set for the whole economy.

For this reason, we have also looked at the returns over the 10- and 30-year period of the FTSE All Share and the S&P500 indices, both of which are what we consider to be mature equity markets, with sufficient historical data to produce reasonable estimates of the risk premium. While there are other European equity markets that may be mature, such as the German DAX index, they tend to be dominated by a few large companies, and are not representative of a well-diversified portfolio.

*Choice of Risk-Free Rate*

For purposes of estimating the equity risk premium it is necessary to estimate the risk-free rate over the same historical period as the historical equity returns. Over each period, there is a choice of government security that could be used as a proxy for the risk free rate. In this study we have chosen to take the average yield on a selection of government securities as an estimate of the risk free rate at that point in time (see Appendix C for data set)

*Choice of Averaging Process*

Controversy exists about whether average realised historical equity return should be calculated using either geometric or arithmetic averages.[11]

The arithmetic versus geometric controversy is basically about market efficiency and how one believes the stock market functions. Market efficiency implies that equity returns are serially independent (i.e. no mean reversion and no method of predicting future returns). In

11 Geometric means are calculated by taking the starting point and calculating the average compound rate of return over the period that would arrive at the end point.

these circumstances, the correct estimator of the future market return is the long term ex post arithmetic mean.

There is no conclusive answer to the question of whether arithmetic or a geometric mean should be used. The empirical evidence surveyed in Fama (1998) generally supports the idea that prices do seem to be weak and semi-strong efficient but that markets are not strong form efficient (there are theoretical reasons why strong-form efficiency is unlikely in Grossman-Stiglitz (1980)). But there are some well known empirical anomalies.

On balance we favour the use of arithmetic means to calculate the ERP using historical data. We believe this is consistent with the majority academic viewpoint and current evidence regarding the efficiency of equity markets.

This paper presents estimates of the ERP using both arithmetic and geometric averages.

***Results***

The following table summarises historical equity returns

**Table 3.4**
**Comparison of historical equity returns**

| Sample period | Market | Arithmetic mean | Geometric mean |
|---|---|---|---|
| **1991 - 2001** | | | |
| | Portugal PSI20 index[1] | 22.13% | 18.46% |
| | FTSE all share | 11.48% | 11.01% |
| | DAX index | 17.41% | 15.66% |
| | S&P500 | 16.12% | 15.56% |
| **1971 - 2001** | | | |
| | DAX index | 11.16% | 9.23% |
| | FTSE all share | 13.24% | 10.99% |
| | S&P500 | 10.99% | 9.87% |

*Source: NERA analysis of Bloomberg data. 1: Portuguese index only available from 1992 onwards, so the 9 year average is quoted.*

The following table summarises ex post estimates of the Equity Risk Premium for European Indices:

**Table 3.5**
**Equity market risk premium estimates for European indices**

| Sample method and period | Market used | Average total returns on market[1] | Average risk-free rate[2] | Equity market risk premium |
|---|---|---|---|---|
| **Arithmetic mean** | | | | |
| 10 years | Portugal PSI20 index | 22.13% | 5.55% | 16.58% |
| 10 years | FTSE all share | 11.48% | 7.33% | 4.15% |
| 10 years | DAX index | 17.41% | 5.62% | 11.79% |
| 10 years | S&P500 index | 16.12% | 6.23% | 9.89% |
| 30 years | FTSE all share | 13.24% | 7.33% | 5.91% |
| 30 years | DAX index | 11.16% | 5.62% | 5.54% |
| 30 years | S&P500 | 10.99% | 6.23% | 4.76% |
| **Geometric mean** | | | | |
| 10 years | Portugal PSI20 index[1] | 18.46% | 5.54% | 12.92% |
| 10 years | FTSE all share | 11.01% | 7.18% | 3.83% |
| 10 years | DAX index | 15.66% | 5.41% | 10.25% |
| 10 years | S&P500 index | 15.56% | 6.17% | 9.39% |
| 30 years | FTSE all share | 10.99% | 7.18% | 3.81% |
| 30 years | DAX index | 9.23% | 5.41% | 3.82% |
| 30 years | S&P500 | 9.87% | 6.17% | 3.70% |

*Source: NERA analysis of Bloomberg data. 1: Equity returns defined as the average annual return on the indicated stock market. 2: The risk-free rates over the same period are averaged using the same methodology as the average of the market returns.*

The results in this table are difficult to interpret. Most obviously they demonstrate that calculations of the equity risk premium are sensitive to the index that is chosen, the historical time period, and the averaging process.

Ex post equity risk premia derived using an arithmetic averaging process lie in the range 4.8-16.6%. Ex post equity risk premia derived using a geometric averaging process lie in the range 3.8-12.9%.

We favour the use of arithmetic averages to calculate the ERP and the use of a longer period. For this reason we believe that the best ex post estimates of the ERP are derived by looking at the 30 year arithmetic average of realised returns for the FTSE and SP5000. These suggest a range for the ERP of 5-6%.

Ex post equity risk premia for the Portuguese stock market are only available for a 9 year history and are in the range 12.9%-16.6%. But these estimates are only based on 9 years of historic data, coinciding with a period of high equity returns elsewhere in the world. For this reason, it would appear that an estimate of the Portuguese ERP based solely on 10 years of historic data would be an over-estimate of the true Portuguese ERP.

### 3.3.2. Semi-Ex-Ante and Full Ex-Ante Approaches

#### 3.3.2.1. *Semi-ex-ante*

The equity risk premium is an expectational concept, representing the expected excess return for equities over expected risk free returns, over a single period. Increasingly, discussions in UK regulatory applications of the CAPM have focused on whether there are better measures of investors' expectations than historic outturns.

Jenkinson (1993) proposed the use a "semi ex ante estimate" of the equity risk premium, calculated as the difference between real returns on equities over *long run* historic periods minus real returns on index linked gilts averaged over *recent* time periods. Jenkinson's rationale for using a semi ex ante approach is his view that there have been prolonged periods during which gilt returns have been negative in real returns suggesting that investors have systematically underestimated the rate of inflation. Because of this, an estimate of the real risk free rate using long run ex-post real returns on gilt-edged securities will be biased downwards.

**Table 3.6**
**Equity market risk premium estimates for European indices**

| Sample method and period | Market used | Average total returns on market[1] | Average risk-free rate[2] | Equity market risk premium |
|---|---|---|---|---|
| **Arithmetic mean** | | | | |
| 10 years | Portugal PSI20 index | 22.13% | 5.15% | 16.98% |
| 10 years | FTSE all share | 11.48% | 5.20% | 6.28% |
| 10 years | DAX index | 17.41% | 4.55% | 12.86% |
| 10 years | S&P500 index | 16.12% | 4.93% | 11.19% |
| | | | | |
| 30 years | FTSE all share | 13.24% | 4.33% | 8.91% |
| 30 years | DAX index | 11.16% | 5.04% | 6.12% |
| 30 years | S&P500 | 10.99% | 7.66% | 3.33% |
| | | | | |
| **Geometric mean** | | | | |
| 10 years | Portugal PSI20 index[1] | 18.46% | 5.15% | 13.31% |
| 10 years | FTSE all share | 11.01% | 5.20% | 5.81% |
| 10 years | DAX index | 15.66% | 4.55% | 11.11% |
| 10 years | S&P500 index | 15.56% | 4.93% | 10.63% |
| | | | | |
| 30 years | FTSE all share | 10.99% | 4.33% | 6.66% |
| 30 years | DAX index | 9.23% | 5.04% | 4.19% |
| 30 years | S&P500 | 9.87% | 7.66% | 2.21% |

*Source: NERA analysis of Bloomberg data. 1: Equity returns defined as the average annual return on the indicated stock market. 2: The risk-free rates are given in Table 3.5 above.*

The results in this table are slightly higher that the results of the ex post approach, reflecting the fact that the current risk free rate estimates are lower than the historical averages. The semi ex ante estimates of the ERP for the FTSE, DAX and SP500 indices for 30 years of historic data using arithmetic averages are in the range 6-8%. Again, since the Portuguese market has only 10 years of historic data any conclusions drawn are less robust, but there is evidence based on this methodology to suggest that the ERP for the Portuguese market is higher than the DAX or SP500.

We note two criticisms of Jenkinson's approach:

- First, the assumption that investors have systematically underestimated the rate of inflation over a long period of time remains unproved. A number of commentators have cast doubt on such an assumption.[12]

- Second, Jenkinson's approach is that it assumes that it is the *equity returns* in the market that are constant over time rather than the equity *risk premium.* In other words, it assumes that there is no relationship in practice between the risk free rate and market returns. Casual evidence does not support this assumption.

### 3.3.3. Ex-Ante Approach

An alternative approach described as a "full ex ante" approach, is to consider evidence on current investors' expectations of equity returns instead of evidence on historical long run outturns of equity returns.

***Survey Evidence***

The table below summarises the results of surveys, in both the UK and US, which have been referred to in a regulatory context. We summarise comments made on the robustness of these results.

12 Draper and Paudyal (1995) record such a view: "It is unlikely on the basis of current evidence available to us about markets and their use of information [ie. the efficient market hypothesis] that investors would systematically underestimate inflation over a long period of time...It is premature on the basis of current knowledge to believe that investors systematically underestimated inflation. It seems implausible that all investors around the world systematically underestimated inflation".

**Table 3.7**
**Survey evidence regarding equity risk premium**

| Survey | Equity risk premium: findings | Robustness / comment |
|---|---|---|
| **UK SURVEY EVIDENCE** | | |
| UK Strategy Forecasts at Investment banks | range of 2% - 5% reported | Range of market premia from UK strategists from SSSB, Deutsche Bank and Morgan Stanley. |
| NERA 1998 UK Analysis | 3% – 4% mean estimate | Sample size of six analysts only. Answers show wide variation |
| Credit Lyonnais Securities (CLSE) 1998 | 2.75% - 7.2%, based on estimates on required returns on water equity | The survey did not ask investors for direct estimates of equity risk premium<br>OFWAT/OFGEM interpreted a range of 2.7-4.2%.<br>The LBS suggested the range could be approx. 2% higher |
| PriceWaterhouseCoopers (1998) | 7 funds reported 2 – 3%<br>3 funds reported -1 - 1%<br>2 funds reported 6 – 8% | Polled 12 big pension fund managers in the UK on their expected market premium in the next 15 years. |
| MMC / Bgas 1993 | 3.37% - 3.5%, based on reported average 7.0% for expected equity returns. | Sample size of eight fund managers responses considered. |
| **US SURVEY EVIDENCE** | | |
| Welch 1998 (US Financial economists)[13] | 6%<br>mean estimate | 70 financial economists; estimates varied between 4% and 8% |
| Harvard Business review (1995) | Most corporations used 5%;<br>M&A groups used 7%<br>based estimates on historic rather than forward-looking data. | Best practices study among investment banks, M&A groups and 27 leading North American corporations. |
| Carleton and Harlow (1993), US, using database of analysts' forecasts | 6.5% for period 1982 - 1990;<br>7.5% for period 1989 - 1993 | Methodology approved in US rate setting cases |
| Harris and Martson (1992), US, using IBES database of analysts' forecasts | 6.5%<br>based on expected return for equity market minus long term yields on government bonds | Methodology approved in US rate setting cases |

13 Welch (1998) "Views of financial economists on the equity premium and other issues", Working paper, Anderson Graduate School of Management, UCLA, April

We note that US survey evidence on the size of the equity risk premium is considerably more robust than current UK evidence. US analysts' forecasts of expected equity returns are contained in large databases, updated frequently, and such evidence is regularly used as evidence on the appropriate allowed cost of equity in US rate cases. In the UK, databases of analysts forecasts have recently become available but we are not aware of the results of the analysis on such databases.

The results from US surveys also tend to be higher than the results from UK surveys. This is hard to justify given that casual evidence shows stock market returns between the UK and the US to be highly correlated.[14]

We are not aware of survey evidence on the size of the equity risk premium based on the Portuguese market or the wider Euro market.

*Evidence from Price-Earnings Ratios*

An alternative method for estimating an equity risk premium, often used by city analysts, is to In addition to the two primary methodologies, the 'economic view' provides a third perspective, which is a useful check on the estimates. This approach does not require historical data or corrections for country risk, but does assume that the market, overall, is correctly priced. Assuming the following valuation model for stocks that is essentially the present value of dividends growing at a constant rate:

> *Share Price = Expected earnings/share next period / (Required return on equity – expected growth rate)*

Using this model, this implies that the required return on market equity ($R_e$) is:

$$R_e = (\textit{Expected earnings / market price}) + \textit{expected earnings growth rate};$$

Using this model to calculate the required return on the market index, defining the required return on the market portfolio ($R_m$) as the sum of the ,market ERP ($R_m$-$R_f$) plus the risk free rate, it therefore follows that the market ERP can be expressed as:

$$ERP = (E/P)_{MARKET\ INDEX} + (\textit{expected earnings growth rate})_{MARKET\ INDEX} - R_f$$

The advantage of this approach is that it is market-driven and uses current data; hence it does not require any historical data. The table below shows the implied equity premiums in

14 An interesting comment on the use of analysts forecasts for estimating the equity risk premium was made by Wadhwani (1999). He considers that investors' current expected returns are too high. For this reason, he considers that survey results on the equity risk premium (such as that by Welch (1998)) often over estimate the size of the equity risk premium. Wadhwani presents evidence that shows how analysts forecasts of earnings typically overestimate actual earnings growth. He shows that sell-side analysts forecasts are typically higher than buy-side forecasts.

the European market based on the current P/E ratios of the index, a real risk-free rate for Europe at 2.94%, and a real earnings growth rate of 4% across Europe.

**Table 3.8**
**Implied equity risk premium based on current P/E ratios**

| Index | Country | Current P/E | Implied ERP[1] |
|---|---|---|---|
| Portuguese PSI20 index | Portugal | 20.07x | 6.04% |
| FTSE 100 | UK | 30.42x | 4.85% |
| FTSE All Share | UK | 29.88x | 4.91% |
| DAX | Germany | 58.79x | 3.26% |
| Bloomberg European 500 | Europe | 27.13x | 5.24% |
| FTSE Eurotop 300 | Europe | 26.91x | 5.28% |
| FTSE Eurotop 100 | Europe | 29.00x | 5.01% |

*Source: NERA analysis of Bloomberg data. 1: Based on a long-term real risk-free rate of 2.94%% and an annual earnings growth rate of 4%. The real interest is calculated as (1+5%) / (1+2%) – 1 based on an inflation assumption of 2%.*

Using this methodology, the implied ERP is 3-6% for the chosen market indices. Excluding the DAX, the implied ERP is 5-6%.

The results are highly dependent on the assumption of 4% real earnings growth for all countries. This is consistent with an upper bound of academic estimates of the growth of output in most major economies, but is slightly higher than observed historical long run EPS growth for most major economies. For the US, EPS growth since WWII is around 3%. Using an assumption of EPS growth of 3% rather than 4% would increase the implied ERP by around 1%. This would mean the above estimates are slightly downwardly biased.

### 3.3.4. Academic Evidence on the Equity Risk Premium

The equity risk premium has attracted significant recent academic debate, partly in response to the bullish equity markets observed in the US economy in the 1990s.

Siegel (1998) argues that estimates of the ERP based on historical averages are rather meaningless since "...stocks have been chronically undervalued throughout history. This has occurred because most investors have been deterred by the high short-term risk in the stock market and have ignored their long-term record of steady gains...One interpretation of the current bull market indicates that investors are finally building equities up the level that they should be on the basis of their historical risks and returns." Siegel's key argument is that even though equity returns are about three times as volatile as bond returns over a one year horizon, empirical evidence shows that over a 20 year horizon shares are less volatile than bonds. Glassman and Hassett (1998) argued that Siegel's findings suggested that "....there should no need for an ERP at all."

Wadhwani (1999) considers Siegel's evidence to be remarkable and evidence of the fact that in the long run the return on equity does equal the cost of capital. However, Wadhwani argues that there are a number of reasons why risk over the short horizon is relevant:

> *"For example, some individuals may be close to retirement, and borrowing constraints may preclude the young from driving the price of equities up to yield a zero risk premium. Second, with a probabilistic length of life, not even the young would accept a zero risk premium. Third, once investment decisions are delegated to a fund management company, asymmetric information and moral hazard considerations give rise to standard agency problems. Pension fund managers are reviewed regularly. It would be extremely rare just to leave one's money with the same manager for twenty years without regular, interim performance reviews."*

Overall, Wadhwani argues that "notwithstanding a variety of intriguing papers on the subject, our theory of the equity risk premium is seriously incomplete. Moreover, the ERP appears to display an ability to move pretty substantially, and we, as economists have not always been able to explain it fully".

An alternative interpretation of the rising share prices of the 1990s is that they are rather exceptional and should not be taken as normal. For this reason, many academics continue to argue that the most appropriate estimate of the equity risk premium is that based on long run arithmetic averages of historical returns, see Cooper and Currie (1999).

In his paper on Railtrack's cost of capital, Jenkinson (1998) concludes that for investors with a five year time horizon the ERP lies in the range of 4.8-6.7%.

### 3.3.5. Regulatory Precedent

Recent UK regulatory estimates by Ofgem, the ORR and Ofwat of the UK equity risk premium are in the range of 3.5-5%. The Competition Commission (2000) used an equity risk premium of 4% in its review of the price limits for Mid Kent Water and Sutton and East Surrey Water. These estimates of the equity risk premium rely heavily on small sample survey evidence of the equity risk premia by CLSE (1999), NERA (1998) and other evidence from Investment Bank analysts.

We remain concerned that recent UK survey evidence used by Ofgem (and also Ofwat) is not sufficiently robust to be used to derive an estimate of the equity risk premium. Ofwat and Ofgem's interpretation of the CLSE survey for instance was that it implies an equity risk premium of 2.4-4.7%. Cooper and Currie (1999) , from the London Business School argue however that other interpretations of the CLSE survey data could lead to a post tax cost of equity that is 1.7% to 2.5% higher.

It should not be discounted that low estimates of the equity risk premium produced by analysts from investment banks would lead to a lower discount rate giving higher valuations to assets. Until wide ranging surveys of investors are available as evidence, then the views of analysts need to be treated with caution.

Although the CAPM is not widely used in the US to estimate the cost of equity, in those rate of return cases where it is used, estimates of the equity risk premium are generally in the range of 6-7%. Such estimates are based on detailed survey data from the IBES database, and historical evidence.

In recent decisions, Australian regulators have concluded that the market risk premium is most likely to lie in the range of 5.0% to 7.0%. The most recent regulatory decision by the ACCC in the price review of Sydney Airports used an equity risk premium of 6%.

### 3.3.6. Conclusions on the Equity Risk Premium

The following table summarises our conclusions on the ERP based on the approaches we have considered.

**Table 3.9**
**ERP Summary Evidence**

| | Ex Post | | Semi Ex ante | | Survey | | P/E Approach | |
|---|---|---|---|---|---|---|---|---|
| | Lower | Upper | Lower | Upper | Lower | Upper | Lower | Upper |
| Portuguese | 12.9% | 16.6% | 13.3% | 17.0% | - | - | 6% | 7% |
| EU/US | 5% | 6% | 6% | 8% | 5%(US)<br>2%(EU) | 7%(US)<br>7%(EU) | 5% | 6% |

We believe that - compared to the rather weak survey evidence - more weight should be attached to estimates of the ERP based on historic data and market based evidence such as that derived by analysis of P/E ratios, and worldwide evidence such as that used in US rate cases all of which suggest an ERP in the range of 5-7%.

To the extent that capital markets are "perfect", we would not expect significant differences in equity risk premia across countries. We have taken the equity risk premium for the Portuguese market to be around 6.0 - 7.0%, and 5.0% - 6.0% for the European market as a whole.

We believe that these estimates of the equity risk premium are consistent with world estimates of the equity risk premium and the methodology used to derive these estimates consistent with best international regulatory practice, such as that observed in the US and Australia.

## 3.4. Beta

Beta is a measurement of the "non-diversifiable" risk of an asset relative to the risk of the market portfolio, and is defined as the ratio of a covariance to a variance. Only EDP holding is publicly quoted whereas we need to estimate betas for two subsidiaries: EDPD and REN. In a previous cost of capital study ERSE'S advisor assumed that the beta for each company (REN and EDPD) would be equal to the group beta.

In order to derive disaggregated betas, we have looked at a number of sources of evidence:

- Beta for EDP holding;
- Evidence from European electricity companies that are primarily engaged in transmission and distribution companies;
- Beta for comparator companies used by European regulators in recent reviews.

In order to select relevant comparators for EDPD and REN, we have looked at a number of major publicly traded European utilities, categorised by the primary activities that they are involved in. A more detailed analysis of the choice of comparators is in Appendix C.

### 3.4.1. Beta for EDP holding

EDP holding's beta is observable (as the holding is quoted) and was used by ERSE's advisor as a proxy for both EDPD's and REN's beta.

Table 3.9. below shows that for EDP Holding, the beta with respect to the national market is 0.49 and 0.56 over the five- and two-year period respectively. This remains roughly in line with what ERSE used at the last tariff review (0.52 for both REN and EDPD). Beta is lower when assessed on the basis of a European index, however (0.36 over a 2-year period).

If we were to choose different betas for each segment of the business, according to CAPM theory, the weighted average of the betas of each asset (weighed by the market value of the asset) should give us the portfolio beta (ie the beta of EDP holding). The weights should be the proportion of assets in each activity. According to the privatisation prospectus EDP holding's operating profits and net assets as of 31 December 1999 are as follows:

**Table 3.10**
**EDP Holding's different business interests[15]**

| | Generation | Transmission | Distribution | Other |
|---|---|---|---|---|
| Operating Profits | 53% | 10% | 37% | 0% |
| Net Assets | 36% | 12% | 37% | 15% |

*Source: Pages 4 and F-32 of Privatisation Prospectus*

### 3.4.2. Betas for comparator companies

We have looked at two main criteria for assessing the degree of comparability between European electricity companies and EDP businesses under consideration:

- The percentage of their activities in the electricity market;
- The percentage of their sales in the domestic market.

For the first criteria, it would have been preferable to identify the exact split between the main activities in the electricity sector (i.e. generation, transmission, distribution). However, this information was not readily available. Secondly, as EDP predominantly operates in the national market, we have looked for companies with a high proportion of their sales coming from the domestic market.

Data for the relevant companies are presented in Table 3.11 below. Equity betas are calculated using weekly returns so that it provides enough data for a robust estimate to be achieved.

Two relative indices are considered: the own country index in which the companies are primarily quoted, and the Bloomberg European 500 index, which is a capitalisation-weighted index of the 500 most highly capitalised European companies. With the latter, a 5-year estimate of the betas is not available, as this index was only developed on December 31, 1996. This allows for an estimation of the cost of capital based on national benchmarks and another based on international benchmarks.

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15 The percentage weights shown do not reflect the fact that EDP sold 70% of REN to the Portuguese government however these are the relevant weights for our calculation given that this acquisition is a recent development and that betas are calculated at least over a two year period (over the most of which REN was a wholly owned subsidiary of REN).

**Table 3.11**
**Estimates of beta for European electricity companies over 2 and 5 year period[1]**

| | Debt/ equity ratio | Effective tax rate | 5 year estimate (own index) | | 2 year estimate (own index) | | 2 year estimate (BE500) | |
|---|---|---|---|---|---|---|---|---|
| | | | Equity beta | Unlevered beta | Equity beta | Unlevered beta | Equity beta | Unlevered beta |
| **Own estimate** | | | | | | | | |
| Electricidade de Portugal SA | 72.09% | 37.49% | 0.69 | 0.49 | 0.81 | 0.56 | 0.52 | 0.36 |
| **Distribution** | | | | | | | | |
| Viridian Group Plc | 104.95% | 13.63% | 0.41 | 0.24 | 0.26 | 0.14 | 0.31 | 0.16 |
| Bewag AG | 13.15% | 41.80% | 0.34 | 0.31 | 0.22 | 0.20 | 0.23 | 0.21 |
| Del - Dunantuli Aramszolgaltato Rt | 0.00% | 20.67% | 0.32 | 0.32 | 0.32 | 0.32 | 0.18 | 0.18 |
| **Average** | | | | **0.29** | | **0.22** | | **0.19** |
| **Transmission** | | | | | | | | |
| National Grid Group Plc | 126.34% | 23.33% | 0.77 | 0.40 | 0.87 | 0.44 | 0.81 | 0.41 |
| Red Eléctrica de España SA | 57.07% | 34.51% | | | 0.55 | 0.40 | 0.68 | 0.49 |
| **Average** | | | | **0.40** | | **0.42** | | **0.45** |
| **Generation** | | | | | | | | |
| Powergen Plc | 139.13% | 8.13% | 0.39 | 0.18 | 0.19 | 0.08 | 0.21 | 0.09 |
| Oesterreichische Elektrizitaetswirtschafts (Verbund) AG | 90% | 31.78% | 0.69 | 0.20 | 0.95 | 0.24 | 0.39 | 0.10 |
| **Average** | | | | **0.19** | | **0.16** | | **0.10** |
| **Integrated** | | | | | | | | |
| Endesa SA | 241.45% | 37.31% | 0.78 | 0.36 | 0.69 | 0.27 | 0.6 | 0.24 |
| Iberdrola SA | 81.57% | 29.34% | 0.70 | 0.45 | 0.55 | 0.35 | 0.55 | 0.35 |

| | Debt/ equity ratio | Effective tax rate | 5 year estimate (own index) | | 2 year estimate (own index) | | 2 year estimate (BE500) | |
|---|---|---|---|---|---|---|---|---|
| | | | Equity beta | Unlevered beta | Equity beta | Unlevered beta | Equity beta | Unlevered beta |
| Hidroelectrica Del Cantabrico | 86.52% | 29.12% | 0.70 | 0.46 | 0.72 | 0.45 | 0.77 | 0.48 |
| Union Electrica Fenosa SA | 106.61% | 40.02% | 0.74 | 0.44 | 0.56 | 0.34 | 0.57 | 0.35 |
| Scottish & Southern Energy Plc | 70.46% | 19.74% | 0.45 | 0.30 | 0.39 | 0.25 | 0.29 | 0.19 |
| Scottish Power Plc | 78.99% | 18.58% | 0.64 | 0.34 | 0.42 | 0.26 | 0.33 | 0.20 |
| Edison SPA | 33.97% | 25.98% | 0.86 | 0.67 | 0.64 | 0.51 | 0.59 | 0.47 |
| Enel SpA | 71.96% | 45.70% | N/a | N/a | 0.41 | 0.29 | 0.31 | 0.22 |
| ACEA SpA | 30.93% | 10.28% | N/a | N/a | 1.1 | 0.86 | 0.95 | 0.74 |
| AEM SpA | 20.93% | 11.68% | 0.81 | 0.71 | 1.27 | 1.07 | 1.27 | 1.07 |
| Neckarwerke Stuttgart AG | 0.74% | 90.21% | 0.39 | 0.39 | 0.33 | 0.33 | 0.42 | 0.42 |
| RWE AG | 28.46% | 27.66% | 0.74 | 0.62 | 0.63 | 0.52 | 0.62 | 0.51 |
| EVN AG | 43.02% | 25.07% | 0.70 | 0.54 | 0.84 | 0.64 | 0.56 | 0.42 |
| Sydkraft AB | 99.63% | 33.05% | 0.31 | 0.19 | 0.31 | 0.19 | 0.28 | 0.17 |
| Electrabel | 52.53% | 23.25% | 0.80 | 0.61 | 1.02 | 0.73 | 0.71 | 0.51 |
| ELMU Rt. | 4.84% | 17.49% | 0.49 | 0.48 | 0.47 | 0.45 | 0.52 | 0.50 |
| **Average** | | | | **0.47** | | **0.48** | | **0.44** |

*Source: NERA analysis of Bloomberg data. The categories are based on Bloomberg categorisation. 1: These betas are calculated using weekly betas from 2/99 to 1/01 and 2/96 to 1/01 respectively. For those companies with less than 5 years' worth of history, a 5-year equity beta cannot be estimated.*

EDP Holding is involved in four major areas of activities. Below, we draw inferences from the comparator companies for estimating the beta of each of these activities.

*CPPE (generation)*. All publicly owned generators that we have looked at also have retail business, so it is not possible to separate between these to businesses. Close comparators may be PowerGen, and Verbund.[16] Furthermore CPPE sells all its power under PPAs so these comparators will be at best imperfect. The asset beta´s for both companies are very low relative to the generally perceived risk of generation activities. The average beta is 0.10 for a 2-year beta estimated on a local or European market index (the 5-year beta is slightly higher, indicating a possible recent reduction in risk).

*REN (transmission)*. For transmission, we have examined two comparator companies: NGC in the UK and Red Electrica in Spain. The average asset beta was around 0.40 if estimated against their own market index and 0.45 if estimated against the European index.

*EDPD (distribution)*. For distribution comparators, betas are relatively low, standing at around 0.2 if estimated over a 2-year period or at 0.3 if estimated over a 5-year period (own index).

*Others:* It is assumed that the remainder of the business will have the same risk exposure as the company as a whole, and thus would have a beta of 0.52, which is the average of the current betas over two and five-year period.

In addition, we note that the average of the betas for the integrated electricity companies are roughly in line with the EDP Holdings estimate, even though EDP's estimate based on European indices is lower (0.36) than the average for integrated companies (0.44).

In the Table below, we summarise the information collected for estimating the beta of EDP holding and its various subsidiaries through the use of comparators, on the basis of a local or a European index.

16 Another potential comparator, International Power (ex National Power), is not considered because it is not sufficiently focused in its national market to be considered a relevant comparator.

**Table 3.12**
**Summary Estimation of Asset Beta by activity**

| | Comparators (average) | | | | EDP Holding |
|---|---|---|---|---|---|
| | **Generation** | **Trans.** | **Dist.** | **Other** | |
| Own index 2-year | 0.18 | 0.4 | 0.29 | | 0.49 |
| Own index 5-year | 0.08 | 0.42 | 0.22 | | 0.56 |
| European index 2-year | 0.09 | 0.45 | 0.19 | | 0.36 |
| Weighted average observed | | | | | ***0.47*** |
| Weighted average comparators | 0.12 | 0.42 | 0.23 | 0.52* | ***0.26*** |
| ***Weights (Asset %)*** | 36% | 12% | 37% | 15% | |

** NERA assumption.*

It is apparent from the previous table that the comparator betas are inconsistent with observed beta for EDP-holding.[17]

### 3.4.3. Betas estimated by other European electricity regulators

Another piece of information which can be useful when estimating beta is to examine at the values used by other European electricity regulators at recent regulatory reviews.

*Ofgem,* the regulator of electricity services in England and Wales, when reviewing retail prices charged by the RECs in May 1999, used an unlevered (or asset beta) comprised between 0.45 and 0.55, which was equivalent to an equity beta of 1. In June 2000, for reviewing transmission prices that NGC is allowed to charge, Ofgem used an unlevered beta of 0.3 to 0.4, which gave an equity beta of 1. This indicates that they considered distribution to be marginally more risky than transmission activities.

The Italian regulator of electricity services (***Autorità per l'energia elettrica e il gas***) made a similar assumption in August 1999 and used an equity beta of 0.43 for transmission activities and an equity beta of 0.76 for distribution activities.

Finally, in their review of prices for both transmission and distribution of electricity (Feb 2000), the ***Deutsch Office for Energy Regulation*** (Dte) considered an unlevered beta comprised between 0.3 and 0.5 for both activities, which also translated into an equity beta of 1.

[17] In fact we would need to assume that the asset beta for EDP holding's other businesses is close to 2 in order to obtain a beta in line with the observed .47 value.

### 3.4.4. Conclusion on beta estimation

Table 3.12 shows that using data from comparator companies would yield a beta for the EDP holding (based on a weighted average of activity betas using asset percentages as weights) which would be much lower than the observed beta (as an average of all calculation methods).

In addition, given our analysis of the relative risk for the various activities (see Appendix B), we found that distribution activities are likely to be riskier than transmission activities, despite the findings based on a limited number of comparator companies. This is also confirmed by the opinion of other European electricity regulators, who have usually tended to assume that distribution activities are riskier and should therefore be allocated a higher beta. Furthermore the average comparator asset betas for distribution are considerably lower than the betas that have been used by other European regulators for these two activities. Even for the Italian case (in which the lowest equity betas where assumed) the assumed equity beta of 0.73 for distribution is significantly higher than the average observed equity betas of the relevant comparators which for the 5 year - own index (which yields the highest values) is equal to 0.35.

Given that these results based on a small sample of comparators are inconsistent with other evidence on the level and relative size of the risks of the activities of REN and EDPD we have not followed a comparator based approach in order to derive the betas of each firm. We have thus adopted an estimation based on the observed beta value of EDP holding (of which, until recently, REN and EDPD where wholly owned subsidiaries). As was mentioned above the estimated beta for EDP holding is roughly in line with the average beta for European utilities this suggests that the observed EDP holding betas are a fairly accurate reflection of the risks of an European integrated utility. There is some indication that the beta estimate for EDP holding based on the European market index may be downwardly biased, ie may result in an estimate of the cost of capital that is below the true cost of capital of the company.

Given our analysis of the risks involved in the activities of REN and EDPD (see B.1.3) and the general consensus that distribution activities entail a somewhat greater risk than transmission activities we have adopted a higher beta EDPD than for REN. If we estimate the beta for EDP holding calculated on a domestic index as being comprised between the 2-year and the 5-year estimate (0.49 to 0.56), we have assumed that beta for transmission is at the lower end of this range (0.45) and beta for distribution is at the upper end (0.56). For betas values calculated using a European index, we have followed an analogous procedure resulting in betas of 0.30 for transmission and 0.45 for distribution.

# 4. ESTIMATING THE COST OF DEBT

The cost of debt can be expressed as the sum of the risk-free rate and the company specific debt premium. The company specific debt premium is driven by actual (or implied) credit ratings based on financial characteristics such as market capitalisation, earnings, volatility and business risks specific to the company and/or the sector.

Since debt issued by the subsidiary can be guaranteed by the parent company, the cost of debt for EDP holding represents a reasonable proxy for the cost of debt of EDPD and REN. However, the cost of debt for a stand-alone distribution or transmission business could potentially differ from that of these businesses within an integrated company.

*Evidence on costs of debt finance for 'comparator' companies*

Apart from the information available on current borrowing costs of EdP, evidence is also available on the market costs of debt for companies in the electricity sector in other countries.

Table 4.1. below shows the corporate bonds issued by EDP holding and comparator companies for a variety of maturities, with the spreads over government securities as well as their gearing ratios. The latter is needed in order for us to estimate a debt premium that is consistent with the gearing ratio of EdP. Finally, the Table also gives information on the companies' credit ratings, from which can be inferred some conclusions regarding the impact of optimal financial management on the risk premium for loan capital.

According to this data, the spread on relevant government benchmarks for outstanding electricity companies bond issues are comprised in a range of 94 to 191 basis points. Spreads are much wider for longer maturity bonds, and the extreme of 191 basis points is found for a bond with very long maturity (2039).

The current spread on EDP's outstanding issue (maturing in 2009) seems well in line with other corporate bonds. For instance, Scottish Power has bonds outstanding for similar maturities that trade wider, but that fits with the fact that they have a lower credit rating and higher gearing than EDP. Another similar issue is Endesa, for which a very similar issue trades at a very similar spread. This gives us some comfort in using this current spread in our estimation of the cost of capital.

**Table 4.1**
**Recent debt issues by European electricity companies**

| S&P / Moody Rating | Gearing * (%) | Corporate bond | Current YTM | Spread** vs. benchmark |
|---|---|---|---|---|
| AA / Aa3 | 0.42 | EDP Holding SA, 6.400%, 29/10/2009 | 5.754% | 102.67 |
| NA / NA | 0.39 | Viridian Group Plc, 6.875%, 18/09/2018 | 6.452% | 166.5 |
| A+ / Aa3 | 0.27 | Scottish & Southern Energy Plc, 5.875%, 22/09/2022 | 6.080% | 139.66 |
| A+ / Aa3 | 0.27 | Scottish & Southern Energy Plc, 5.875%, 22/09/2022 | 6.341% | 166.07 |
| A / A1 | 0.54 | Scottish Power Plc, 5.030%, 15/07/2008 | 5.789% | 106.94 |
| A / A1 | 0.54 | Scottish Power Plc, 5.250%, 04/08/2008 | 5.662% | 94.635 |
| A / A1 | 0.54 | Scottish Power Plc, 6.715%, 13/02/2008 | 6.323% | 117.16 |
| A / A1 | 0.54 | Scottish Power Plc, 6.625%, 14/01/2010 | 6.324% | 133.54 |
| A / A1 | 0.54 | Scottish Power Plc, 8.375%, 20/02/2017 | 6.420% | 156.14 |
| A / A1 | 0.54 | Scottish Power Plc, 6.750%, 29/05/2023 | 6.222% | 156.73 |
| A / A1 | 0.54 | Scottish Power Plc, 5.750%, 09/12/2039 | 6.297% | 191.06 |
| A- / A2 | 0.12 | Edison SPA, 6.375%, 20/07/2007 | 5.927% | 128.80 |
| NA / Aa3 | 1.07 | Endesa SA, 4.200%, 25/02/2009 | 5.757% | 102.10 |

*Source: NERA analysis of Bloomberg data.*
* *Gearing is measured as total debt to market capitalisation.*
** *Spreads are measured in basis points (0.01%).*

***Summary***

The various bond markets provide one source of evidence for spreads on EDP debt premia. Companies are also able to raise debt through bank loans, although we have no direct evidence of differential rates on bank loans versus bond rates.

Given the evidence of borrowing costs of EDP and of other companies, our estimate of EDP's debt premium would be in the region of 100 basis points for maturities of around 10 years (which is the maturity used for estimating the risk free rate), regardless of whether this is raised in the domestic or European market.

# 5. CALCULATING THE WACC

## 5.1. Gearing

Gearing is a measure of the ratio of debt to debt plus equity in the company. Since the market returns on debt and equity vary, as do the tax implications of each, this ratio will have a significant impact on the WACC. Debt plus equity is generally measured using market values, i.e. the market capitalisation of the company, because using book values could lead to meaningless results. However, the book value of debt may need to be used as an approximation of the market value of debt.

The WACC used by the regulator should not include inefficient decisions made by the operators. Since the cost of debt will vary as the gearing changes, there is, in principle, an optimal capital structure. Based on comparison with other companies, we can broadly assess whether EDP has an optimal capital structure or not. If we were to modify observed gearing to bring it in line with an optimal capital structure, we would need to also modify the cost of debt which would be affected by such change in gearing.

Based on current market information (see Table 5.1. below), EDP holding's gearing (calculated as debt over market capitalisation) currently stands at 42% (source Bloomberg). This is relatively high when compared to other integrated electricity companies with have a similar rating, such as Enel (25%) or RWE (10%). However, we note that there is considerable scope for increasing gearing and maintaining an acceptable credit rating, as demonstrated by other integrated companies such as the Spanish Endesa (107%) or Union Fenosa (54%).

There is some evidence that suggests the optimal gearing for a regulated wires company is in the range of 50%-60%. OFGEMs recent price review of NGC concluded that a 60% gearing level was appropriate for NGC given the risk characteristics of the industry. NGC however maintained that its optimal gearing was around 50%. OFGEM's 1999 review of distribution suggested that the REC's optimal gearing was 50%. IPART's 1998 discussion paper of the rate of return of distribution networks (IPART Discussion paper 26) gives evidence that suggests that the optimal gearing for electricity distributors may be in the range 50%-60%.

A possible approach for calculating REN and EDP's cost of capital would be to assume that they have an optimal gearing in the 50%-60% and that a gearing outside this range is due to an inefficient capital structure. However even if the 50%-60% where applicable to REN[18] and EDPD it should be noted that the capital structure of EDPD and REN (and that of EDP

[18] For instance any analysis of the optimal gearing of REN should take into account that given its single buyer function (AEE) REN must absorb any deviation between actual and expected fuel price (it is compensated for deviations in period t in period t+2). Given the relatively small size of REN this causes wide fluctuations in its cash-flow. Because of this fact REN's debt may rise significantly in any particular year and could reasonable lead the company to take a conservative approach when it considers its target for gearing.

holding as whole) is in a very large degree the result of their publicly owned past, thus management has not had a chance to influence the financing structures of these companies and it would therefore be inappropriate to penalise them by ignoring their actual capital structure and assuming that they can instantly restructure their capital structure at their will. Given the above we have based our approach on taking the actual gearing of each company. Our approach is consistent with the approach taken by the Monopolies and Mergers Commission´s (MMC, now Competition Commission) and OFGEM´s to calculate the cost of capital for the RECs up to 5 years after their privatisation, as is evidenced in the following passage from OFGEM´s 1999 review of distribution charges

> *The MMC has tended to base its calculations of the cost of capital on the actual rather than the efficient level of gearing. This approach was also adopted by OFFER in the 1996 price control review of NGC's transmission business. However, the circumstances of the PESs are significantly different to those of NGC. The PESs were privatised in 1990 and 1991, and the sector has undergone a significant amount of financial restructuring and take-over activity. In these circumstances, management has had the opportunity to influence the financing structures supporting each distribution business.*

The current gearing measured as debt to market cap of EDP holding is 42%[19]. Given that EDPD and REN are not publicly quoted it is not possible to estimate the debt to market cap for these companies. We have thus chosen to use EDP holding´s actual level of gearing of 42% as a proxy for that of EDPD and REN.[20]

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19 Source: Bloomberg.

20 It should noted that the gearing assumption has a small impact on the cost of capital calculation. Sensitivity tests to the assumed value for gearing revealed that increasing assumed gearing to 60% resulted in decreases of less than 0.4% in our reported values.

**Table 5.1**
**Market Gearing for EDP and comparator companies**

| Company Name | Moody Rating | SP Long term | Debt To Mkt Cap |
|---|---|---|---|
| Electricidade de Portugal SA | Aa3 | AA *- | 42% |
| ***Distribution*** | | | |
| Viridian Group Plc | n.a | n.a | 39% |
| Bewag AG | n.a | n.a | 9% |
| Delmagyarorszagi Aramszol | n.a | n.a | 0% |
| ***Transmission*** | | | |
| National Grid Group Plc | n.a | A+ *- | 43% |
| Red Electrica de Espana | Aa3 | AA- | 50% |
| ***Generation*** | | | |
| Powergen Plc | Baa1 | BBB+ | 92% |
| ***Integrated*** | | | |
| Endesa SA | n.a | A+ | 107% |
| Oesterreichische Elektrizitaetswirtschafts AG | n.a | AA- | 90% |
| Hidroelectrica Del Cantabrico | A1 | n.a | 55% |
| Sydkraft AB | n.a | A+ *+ | 55% |
| Union Electrica Fenosa SA | A1 | A+ | 54% |
| Scottish Power Plc | n.a | A *- | 54% |
| Iberdrola SA | A1 | AA- | 52% |
| Vorarlberger Kraftwerke AG | n.a | n.a | 52% |
| Sondel - Societa Nordelettrica SpA | n.a | n.a | 43% |
| EVN AG | n.a | AA | 34% |
| Scottish & Southern Energy Plc | n.a | A+ | 27% |
| Enel SpA | Aa3 | A+ | 25% |
| ACEA SpA | n.a | AA- | 13% |
| Electrabel | n.a | n.a | 13% |
| Edison SPA | A2 | A- *- | 12% |
| RWE AG | Aa3 | AA- | 10% |
| Jersey Electricity Co. Ltd. | n.a | n.a | 9% |
| International Energy Group Plc | n.a | n.a | 9% |

## 5.2. Tax

In Portugal, the corporate tax rate ("IRC") is currently 32% and there is a local surtax ("Derrama") of 10%, which is levied in some municipalities. This means that a final tax rate of 35.2% is levied on most corporate profits. However, the corporate tax rate is expected to be reduced to 30% as of January 2002. In addition, there is a limit to incremental depreciation as a result of asset revaluation that can be deducted. For those reasons, EDPD has a forecasted effective tax rate for 2002 of 36.4%[21] while REN has a forecasted effective tax rate for 2002 of 38.3%[22] (the difference between corporate and effective tax rates arise because of). We will use these forward looking effective tax rates as the corporate tax rate in our cost of capital calculation. We note that in the cost of capital estimate of ERSE's advisor a 40% corporate tax rate was used.

There has been considerable academic and regulatory debate worldwide surrounding the use of pre- or post-tax formulations of the rate of return, the appropriate conversion formula and the application of statutory or effective tax rates. In principle this stems from:

- A fundamental tension between regulation on the basis of Price Index-linked real revenues and a taxation system which operates in nominal terms; and
- Differences in timing between the depreciation allowed for taxation and that allowed for regulatory purposes.

The effects of these two factors means that the use of a simple formula to take account of taxation in converting from a post tax WACC to a pre-tax WACC. Three formulas have been used by regulators to convert a nominal post tax WACC into a real pre tax WACC. We define the approaches that have been used by regulators to convert a nominal post tax WACC into a real pre tax WACC as follows:

### 5.2.1. Approach 1: The "Macquarie" Approach

Approach 1, known in Australia as the Macquerie approach[23], converts a nominal post tax WACC to a real pre tax WACC as follows:

- **Step 1**: Convert nominal post tax WACC to real post tax WACC by adjusting for inflation using Fisher equation.

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21 Source: EDP forecast.

22 Source: REN forecast.

23 Macquerie Risk Advisory Services (1998) "The Appropriate Level of Taxation to Apply for Gas Distribution Businesses in Conjunction with the CAPM models in the Determination of Regulated Use of System Charges" Submission to the ORG.

- **Step 2**: Convert real post tax WACC to real pre tax WACC by adjusting for the statutory tax rate.

The "Macquarie Approach" defines the real pre tax WACC in terms of the nominal post tax WACC as follows:

$$Real\ Pre\ Tax\ WACC_{Macquarie} = (Nominal\ Post\ Tax\ WACC - I)/((1+I)*(1-t)) \qquad (1)$$

Where I is the inflation rate; t is the corporate tax rate.

### 5.2.2. Approach 2: The "MMC" Approach

Approach 2 is known in the UK as the "MMC" Approach.

- **Step 1**: Converts the nominal post tax return on equity and the nominal pre tax return on debt to their real counterparts
- **Step 2**: Convert the real post tax return on equity to real pre tax return on equity by adjusting for the statutory tax rate

The "MMC Approach" defines the real pre tax WACC in terms of the nominal post tax WACC as follows:

$$Real\ Pre\ Tax\ WACC_{MMC} = (Nominal\ Post\ Return\ on\ Equity - I)/((1+I)*(1-t))*E + (Nominal\ Pre\ tax\ Return\ on\ Debt - I)/(1+I)*D \qquad (2)$$

Where I is the inflation rate; t is the corporate tax rate; E is the proportion of equity; D is the proportion of debt.

### 5.2.3. Approach 3: The "Historical" (or "CSFB") Approach

Approach 3, known (mainly) in Australia as the CSFB[24] or Historical approach, converts a nominal post tax WACC to a real pre tax WACC as follows:

- **Step 1** Convert nominal post tax WACC to nominal pre tax WACC by adjusting for the statutory tax rate.
- **Step 2**: Convert nominal pre tax WACC to real pre tax WACC by adjusting for inflation using Fisher equation.

The "The Historical Approach" defines the real pre tax WACC in terms of the nominal post tax WACC as follows:

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24 Based on the formula proposed by CSFB in relation to the Victoria Gas Access Arrangements

$$Real\ Pre\ Tax\ WACC_{Historical} = Nominal\ Post\ Tax\ WACC/(1\text{-}t)\text{-}I)/(1+I) \quad (3)$$

Where I is the inflation rate; t is the corporate tax rate.

### 5.2.4. Adopted Approach

In general (where expected inflation and the expected tax rate are both positive) the MMC approach will give a lowest estimate of the Real Pre Tax WACC and the Historical approach will give the highest estimate of the Real Pre Tax WACC. Intuitively, this is because the MMC approach scales up for tax a (lower) real WACC whereas the Historical approach scales up for tax a (larger) nominal figure. The differences between the three approaches will increase as inflation increases.[25]

In general it is not possible to say which formula should be preferred in converting a post tax nominal WACC to a pre tax real WACC for the case of EDP or REN. We note that these formulas also ignore the effect of capital allowances on the true tax liabilities faced by EDP.

For the purpose of deriving a pre tax WACC for EDP and REN, the approach we use in this report is the MMC approach. We have applied a taxation adjustment to the real post tax cost of equity to convert to a real pre tax cost of equity. Note that we have chosen the most conservative alternative ie the one which leads to the lowest estimate of the companies pre-tax WACC.

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25 For inflation of around 2% and a tax rate of around 30%, the difference between the three approaches is around 1%.

# 6. RESULTS

On the basis of the conclusions drawn out in previous sections, we calculated the cost of capital for REN. For these calculations, we have used a lower and upper bound for estimates based on the local Portuguese market and on the European market. These results are presented in the Table 5.1. below.

As shown, the nominal pre-tax cost of capital for REN can be estimated in a range of 8.9% and 11.6%. This value indicates that the cost of capital for REN is likely to be significantly higher than the value used by the regulators for the first tariff period which as 8.5% (given that the cost of capital calculations of ERSE´s advisor include customer contributions, which have a zero cost of capital our results are not comparable to theirs).

**Table 6.1**
**Calculation of the cost of capital for REN**

| | Portuguese benchmark | European benchmark |
|---|---|---|
| **CAPM parameters** | | |
| Nominal risk-free rate | 4.75% - 5.25% | 5% |
| Inflation | 2.12% | 1.76% |
| Real risk-free rate | 2.58% - 3.07% | 3.18% |
| Asset beta | 0.45 | 0.3 |
| Gearing | 42% | 42% |
| Tax rate | 38.3% | 38.3% |
| Equity beta | 0.71 | 0.48 |
| Equity risk premium | 6.0% - 7.0% | 5.0% - 6.0% |
| | | |
| **Cost of equity** | | |
| Real Risk-free rate | 2.58% - 3.07% | 3.18% |
| Beta | 0.71 | 0.48 |
| Equity risk premium | 6.0% - 7.0% | 5.0% - 6.0% |
| Real Post-tax cost of equity | 6.9% - 8.1% | 5.6% - 6.0% |
| Real Pre-tax cost of equity | 11.1% - 13.1% | 9% - 9.8% |
| | | |
| **Cost of debt** | | |
| Real Risk-free rate | 2.58% - 3.07% | 3.18% |
| Debt premium | 100 | 100 |
| Pre-tax cost of debt | 3.58% - 4.07% | 4.18% |
| Tax rate | 38.3% | 38.3% |
| Post-tax cost of debt | 3.58% -4.07% | 4.18% |
| | | |
| **WACC calculation** | | |
| Gearing | 42% | 42% |
| Post tax WACC, gross of tax shield | 5.5% - 6.4% | 5% -5.3% |
| Post tax WACC, net of tax shield | 4.9% - 5.7% | 4.3% -4.6% |
| Pre tax WACC real | 7.9% - 9.3% | 7% - 9.4% |
| **Pre tax WACC nominal** | **10.2% - 11.6%** | **8.9% - 9.3%** |

# APPENDIX A. PREVIOUS COST OF CAPITAL ESTIMATION

For the first regulatory period (1999 - 2001), ERSE commissioned a study of EDPD's and REN's cost of capital to an outside advisor. In this Appendix, we give a brief description of the methodology employed and discuss how it compares with international best practice. We then discuss how ERSE applied the results of the study when setting revenues for both regulated firms.

## A.1. Review of Advisor's Study

### A.1.1. Methodological issues

The study used the following formula to calculate the WACC:

$$WACC = k_E * \frac{E}{E + D_{LT} + S} + k_D * \frac{D_{LT}}{E + D_{LT} + S} + k_S * \frac{S}{E + D_{LT} + S} \qquad (*)$$

Where S represents capital contributions (subsidies) and $D_{LT}$ is long-term debt. The study considered that subsidies where equivalent to cost free financing and thus $k_S$ was set to zero.

The study's methodology raises several issues. We discuss each of them in turn below.

***Treatment of subsidies as a source of financing.*** As noted in Section 2, assets that are built through capital contributions should not be included in the regulatory asset base. The WACC value obtained from this expression is therefore not informative for calculating the allowed rate of return on regulatory assets.

In its application, ERSE seems aware of this fact: when they analyse the impact of the tariffs set on the firms' financial equilibrium, it gives financial ratios of EDPD and REN which do not include capital contributions and states that these "are the appropriate values for international comparisons". If the parameters used in calculating the cost of capital on the basis of such expression were known, it would be straightforward to recalculate the cost of capital by excluding capital contributions. However the study does not give enough information so as to reconstruct the capital structure that was used (i.e. the values for E, $D_{LT}$, and S). In any case, it would be most appropriate to calculate the WACC on the basis of a formula that does not include capital contributions, as we recommend in Section 2.

***Use of long-term debt.*** The study only uses long-term debt in its derivation of the capital structure for both companies. As stated by Brealey and Myers,[26] this is strictly not correct:

[26] BM (1996) Principles of corporate finance, p 521

> *"Many companies consider only long-term financing when calculating the WACC. They leave out short-term debt. In principle this is incorrect" and "when short term debt is an important source of financing...the interest cost of short term debt is then one element of the weighed average cost of capital".*[27]

Such element could potentially have a substantial impact on the estimation of the cost of capital. After EDP holding's sale of 70% of REN to the Government, half of REN's debt is expected to be short term.[28] Therefore, in the methodology we are using for estimating the cost of capital, we are recommending to include all debt, including short-term debt.

***Estimating gearing.*** The study used a financial model to forecast the future capital structure of the firm. This approach yields a forward-looking estimate of the capital structure that in principle is correct. However it requires a complex financial model for each of the firms and the forecasts are unlikely to be completely accurate. Furthermore, unless there is any structural change in the firms financing policy, the capital structure is not likely to change significantly.

***Estimating beta.*** The calculation of the cost of equity is based on the CAPM model. Given that neither REN nor EDPD is quoted (only the holding is quoted), it is not possible to observe a beta value for them. The study uses a Reuters estimate of the beta for EDP holding as an estimate of the asset beta for both REN and EDPD.[29] The study then argues that it is in fact a favourable estimate (i.e. upward) for both EDPD and REN as international evidence shows that generation assets are more risky than wires (transmission and distribution).

However, as we discuss in Section B.1.3, EDP holding's generation assets are for the most part covered by PPAs that minimise their risk to the sole issue of being available when dispatched. If that is taken into account (i.e. EDP's generation assets are in fact relatively low risk), the supposed upward bias in the advisor's beta assumption is more than questionable. In our discussion about beta (Section 4), we analyse in which way the beta for transmission and distribution businesses are likely to compare.

**Unlevered beta.** Given its assumption for the unlevered beta (the holding's beta for both the transmission and distribution businesses), the study then applies the gearing in order to calculate a levered beta to be used in estimating the cost of equity using the following formula:

$$\beta_l = \beta_u \left[ 1 + \frac{(1-t)D_{LT}}{E+S} \right]$$

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27 Ibid p 522

28 See ERSE Tarifas 2001 p 422.

29 Note that when the study was conducted both companies where wholly owned subsidiaries of EDP holding.

### A.1.2. Results

Table A.1 gives the main assumptions of ERSE´s advisor

**Table A.1**
**Advisor´s Assumptions**

| | Value | Source |
|---|---|---|
| $r_F$ | 4.0% | Average of Portuguese government bonds |
| $r_D$ | 4.5% | LISBOR+100 BPS |
| $r_M$ | 9.0% | Assumption |
| $T_c$ | 40% | Portuguese corp. tax rate |
| $\beta_U$ | 0.52 | Reuters estimate for EDP holding |

On this basis along with a financial model, ERSE´s advisor calculated the following cost of capital estimates:

**Table A.2**
**Advisor's Estimates of the Post-Tax Nominal Cost of Capital**
**(Asset base includes customer contributions)**

| | REN | EDPD |
|---|---|---|
| 1998 | 6.0% | 5.2% |
| 1999 | 6.0% | 5.2% |
| 2000 | 6.0% | 5.1% |
| 2001 | 5.9% | 5.1% |

## A.2. ERSE's Application of Advisor's Study

When it set tariffs for 1999, ERSE compared the rate of return that REN's transport business and EDPD's distribution business were expected to achieve with the WACC calculated by its advisor and noted that values "were in line". In fact, this was only true for distribution. Given the ROE that the firms were expected to achieve and assuming that the firms achieved ROE was a proxy for the $r_E$, ERSE calculated the expected return to be as shown in the Table below. However it should be noted that ERSE´s estimated return is based book values of debt and equity and on embedded costs of debt and therefore is not comparable and does not reflect a forward looking WACC.

**Table A.3**
**ERSE allowed return post-tax nominal**
**(Asset base includes customer contributions)**

| | REN (including generator sites) | REN transmission business | EDPD |
|---|---|---|---|
| 1999 | 3.0% | 4.9% | 5.0% |
| 2000 | 3.0% | 4.8% | 4.9% |
| 2001 | 3.0% | 4.8% | 4.8% |

The very low value for REN is due to the fact that ERSE decided to disallow REN's land holdings where generators are located from the asset base on which it earns returns. However, even when considering only the return allowed for REN's transmission business, the allowed return *is considerably* lower that the value that was estimated by ERSE´s advisor.

As has already been noted under Portuguese regulation the allowed rate of return for REN is applied to net fixed assets *excluding subsidies* thus for regulatory purposes the relevant cost of capital is one where capital contributions are ignored.[30] Thus according to ERSE allowed rates of return on assets net of customer contributions provide the most relevant figures for international comparisons, and are presented in the table below:

**Table A.4**
**ERSE allowed return post-tax nominal**
**(Asset base excludes customer contributions)**

| | REN | REN (AEE) | REN (GCS) | REN (TEE) | EDPD | EDPD (DEE) | EDPD (CEE) |
|---|---|---|---|---|---|---|---|
| 1999 | 3.2% | 0.1% | 5.5% | 5.4% | 6.6% | 5.4% | 19.4% |
| 2000 | 3.2% | 0.1% | 5.1% | 5.4% | 6.5% | 5.3% | 18.4% |
| 2001 | 3.2% | 0.2% | 5.1% | 5.4% | 6.5% | 5.2% | 18.1% |

However it should be noted again that these values for allowed returns are based on book values for equity and embedded costs for debt and they are therefore *unsuitable* for comparisons with market based forward looking measures of the cost of capital which are used by other European energy regulators in countries such as the UK, Netherlands and Italy.

30 A rate of return for EDPD is never explicitly considered as it does not appear in the revenue formula and is only calculated ex-post given allowed revenues.

# APPENDIX B. EDPD AND REN'S OPERATING ENVIRONMENT

In order to appropriately estimate the cost of capital for each firm, it is important to understand their operating environment, and to estimate the significance of the risks they might be facing, as these risks would affect their cost of capital.

### B.1.1. Overall Regulatory framework

EDPD and REN operate under exclusive concession contracts granted by the Portuguese government and various municipalities. These concessions and licenses are granted for fixed periods ranging from 20 to 75 years, but are subject to early termination under specified circumstances. Upon termination of these licences the fixed assets associated with licences or concessions will in general revert to the Portuguese government or a municipality as appropriate. EDPD and REN would be paid the residual values of these assets upon termination of the concession contracts.

The "Regulamento Tarifario" governs the regulation of EDPD and REN's revenues and specifies the formulas for calculating the yearly revenues that each firm is allowed to earn. At the beginning of a regulatory period (5 years) the regulator sets the parameters for the formulas, such as the return on assets, which will remain unchanged for the regulatory period. On a yearly basis and based on the cost information and other forecasts given by REN and EDPD, the regulator determines their allowed revenues for the next period.

In the following sections, we present the specific regulatory provisions applying to each segment of the electricity system, namely: generation, transmission and distribution.

### B.1.2. Generation

Generators in the Portuguese *Sistema Eléctrico do Serviço Público* (or SEP) have entered into power purchasing agreements with REN. These contracts include a fixed capacity payment and an energy payment. The energy payment is meant to reflect the generator's avoided costs and is indexed to international fuel prices.

EDP holding's wholly owned subsidiary, CPPE, accounts for most generation capacity in the SEP. Unlike generators that operate in a system where there is a wholesale market for electricity, as in UK or Spain, generators in the SEP are not subject to market price risk. If they are available to produce, generators in the SEP are guaranteed cost recovery by the fact that their fixed costs are covered by the capacity payments and their avoidable costs, mainly fuel costs, are covered by the energy payment which itself is indexed to the corresponding international fuel price (ie they are hedged against fuel price risk). The only risk that generators face in the SEP is the availability risk, i.e., if they are not available to generate, they do not get any payment.

Even though generators in other countries, as in the UK, are likely to have a significant proportion of their capacity committed under long-term contracts, it is unlikely that their exposure will be as low as that of generators in the SEP. Furthermore long term contracts that hedge the spot price risk for generators competing in wholesale power markets may not cover the whole asset life of the assets and therefore may have to be renegotiated. Therefore, the risk attached to electricity generation in Portugal is likely to be lower than in other European countries where wholesale power markets are in operation.

*B.1.2.1. Transmission (REN)*

REN has three regulated businesses:

- **Power Procurement** (*Adquisicao de Energia Electrica,* AEE). REN acts as the single buyer for the regulated system or SEP. Assets for this activity account for almost half of REN's regulatory assets (39% in 2000)[31]. As part of this activity, REN is the owner of the sites where the SEP's generation plants are located. For the first regulatory period, ERSE disallowed any return on land.
- **Global System Management** (*Gestao Global do Sistema,* GGS): REN acts as the system and market operator (dispatch, ancillary services and settlement among others). This business accounts for a small proportion of REN's regulatory assets (4% in 2000)[32].
- **Transmission** (*Transporte de Energia Electrica,* TEE): REN manages the transport network. This business accounts for more than half of REN's regulatory assets (57% in 2000).

REN is regulated by a ***cost plus*** revenue formula. The allowed nominal pre-tax rate of return on REN's AAE business assets and on REN's transmission business assets are explicitly included in REN's revenue formula. For the first regulatory period, they where set at zero and 8.5% respectively.

As part of its AEE function, REN bears a financial risk arising from the deviation between expected payments under the PPAs and actual payments. Any difference arising in Period (t) is adjusted by modifying revenues in Period (t+2), using LIBOR+x as a rate of return.

In May 2000 the Portuguese government announced that coinciding with the public offering of approximately 20% of EDP holding it would purchase 70% of REN from EDP. The transaction was motivated by the governments wish to retain ownership control of REN as a company with strategic national importance. As a pre-condition for the purchase of REN by the government, REN distributed an extraordinary dividend payment of approximately PTE 78,700 million to its sole shareholder EDP and REN repaid all its debt to EDP in an amount equal to approximately PTE 21,300 million.

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31 ERSE (2000) Tarifas 2001, p 185.

32 ERSE (2000) Tarifas 2001, p 185

As a result of the purchase REN's capital structure was significantly changed. According to ERSE REN's non-financial debt went from PTE 23,091 million in 1999 to PTE 132,267 million in 2000 (see p 422 of ERSE Tarifas 2001).

*B.1.2.2. Distribution (EDPD)*

EDPD has two regulated businesses:

- **Electric Energy Distribution** (Distribucao de Energia Electrica, DEE): EDPD manages the distribution wires to transport energy from RNT (Rede Nacional de Transporte de Energia Eléctrica) points of reception, or from special regime producers and from the transfrontier connections to final clients. Assets associated with this activity also include measuring and control equipment.
- **Electric Energy Commercialisation** (Comercializacao de Energia Electrica, CEE): This activity includes everything involved in the purchase and sale of electric energy as well as metering, invoicing and collection of payments.

Both businesses are regulated by a revenue cap, which includes a profit sharing mechanism. The revenue formula is not explicitly based on actual costs so there is not explicit value for an allowed rate of return on assets.

EDPD's allowed revenues for distribution are fixed based on forecast values of:

- Energy delivered;
- Level of losses;
- Environmental policy costs (these have not been explicitly considered so far).

EDPD's allowed revenues for retail supply are fixed based on forecast values of:

- Number of final clients;
- Energy supplied to customers;
- Procurement costs (these have not been explicitly considered so far);
- Cost of generation and distribution services.

The allowed revenue in period t is recalculated in period t+2 with actual values and deviations are compensated in the next regulatory period using LIBOR + x. Most of the values that determine EDPD's revenues are not its own costs and EDPD is effectively subject to a price cap on these elements. However, some elements are taken as cost pass-through, such as the costs of generation and distribution services for retail supply.

For both businesses, profits evaluated in period t+2 in excess of a predetermined level are shared with consumers. This represents a one sided risk for EDPD as there is no provision for sharing losses with consumers.

EDPD's revenues are also subject to risk from the fact that under the tariff code, residential tariffs (LV tariffs) cannot increase by more than the inflation rate every year. However, the value of allowed costs not reflected in the LV tariff might be recovered in the tariffs in the following years, up to a maximum of five years. If after 5 years, the Ministry can allow an exceptional rise in tariffs in a discretionary manner.

### B.1.3. Risks faced by REN and EDPD

Below, we present a summary assessment of the risks faced by REN and EDPD.[33]

Regulatory risk. This is the main risk faced by both companies. In particular, the upcoming review that has been opened by the ERSE document in February 2001 has introduced many uncertainties as it may result in substantial changes to the current regulatory framework.[34]

In addition, under the current system the main risk from the regulator for both firms is ERSE's discretion when choosing certain parameters, such as the cost of capital, for the firms' revenue formulas:

- For generation, the regulatory risk is relatively low as generators are remunerated under long term PPAs.
- For REN, the main risk in that respect is whether ERSE will allow a return on sites for generating plants that it holds as part of its AEE function. In addition, there is a financial risk arising from the potential deviation between actual and expected generation costs.
- For EDPD, the main risk is the important degree of discretion allowed by the Regulamento Tarifario when ERSE determines the revenue formulas. For example, the regulator does not have to use an explicit return on EDPD's assets. Distribution appears to be most exposed to regulatory risk.

Other risks affecting the profitability of EDPD and REN are the following:

- ***Demand risk***: EDPD is directly affected by uncertainty with respect to yearly demand, both in terms of energy consumed and in terms of the number of customers in the SEP.

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33 For a further exposition see EDP's privatisation prospectus October 23, 2000.

34 ERSE (2001) "Revisão dos Regulamentos do Sector Eléctrico- Documento de Discussão", 12 February 2001.

- *Risk from an increase in competition*: So far only large consumers are eligible to consume energy outside the SEP and a very limited number of them have actually chosen to do so. Under the current system, if a large number of customers were to leave the system this would cause (average costs) and therefore tariffs to rise. This would probably cause the limit on the increase of residential tariffs to bind.
- *Inflation risk*: Given that REN's rate of return is nominal and its revenues are not corrected by inflation, its real returns are subject to inflation risk.

In the Table below, we present a summary comparative analysis of risk by activity in order to inform our analysis of betas for each activities in particular. From this analysis it seems reasonable to assume that distribution/retail is riskier than transmission (REN), which has similar risks as generators.

**Table B.1**
**Summary comparative analysis of risk by activity**

| | Generation | Transmission | Distribution |
|---|---|---|---|
| Regulatory risk | - | + | ++ |
| Cost side risk | + | - | ++ |
| Revenue risk | + | + | ++ |

With respect to cost-side risk, it appears that the greatest risk is borne by distribution and retail which are regulated by a price cap and thus subject to cost pass through risk, next would be risk borne by generation assets which have basis risk (arising from the fact that their fuel costs may differ from international indices) and availability. Transmission assets face the lowest risk.

With respect to revenue side risk, in the future it is possible that more consumers decide to exit the SEP and purchase their electricity from the SENV (the competitive system). SEP generator's variable revenues cover avoidable costs so as long as they are available their profits will not vary with SEP demand. REN's revenues will vary with ex-post demand but any deviation in period t will be corrected in t+2. On the other hand, EDPD's revenues vary with the number of consumers and energy supplied thus it is subject to demand risk.

# APPENDIX C. CHOICE OF COMPARATOR' COMPANIES

One issue in estimating beta for each of the companies is that only EPD holding is quoted, but EDPD and REN are not independently quoted. In order to estimate their betas, it is useful to draw inferences for comparator companies with a more vertically disintegrated structure. In this Appendix, we present evidence on such comparator companies.

## C.1. Comparators for REN

### C.1.1. REN's AEE business

Most of the assets of REN´s AEE business consist of the land were generation sites in the regulated sector are located. In other countries these sites are usually considered to be part of the generators assets, as they are assets needed for the production of electricity. It therefore seems reasonable that these assets should earn a rate of return that corresponds to generation assets. If these assets had been assigned to the generators they would certainly receive a ROR under the PPAs. Therefore, AEE assets should be assigned a cost of capital analogous to that of the generation function.

Relevant publicly traded comparators (firms with only generation assets and isolated from market risk through PPAs): none, all publicly owned retailers also have retail business, not possible to separate between these to businesses. Close comparators may be PowerGen and Verbund.

### C.1.2. REN's transmission and UGS businesses

These two businesses (transmission wires business and SO operator functions) should be considered together. There are two publicly quoted analogous businesses in Europe (NGC and REE)

## C.2. Comparators for EDPD

EDPD's businesses include distribution and franchised retail. The most obvious comparators are the UK RECs (of which none is quoted) and the Austrian distributors, of which only EVN is quoted (and has considerable generation 25% of what it distributes).

## C.3. Comparative data on relevant companies

In the Table C.1. below, we present data on comparable European companies for which we calculate beta in Section 3.

**Table C.1**
**Comparator information**

| Company | Brief description | Percentage sales by geographical region | Percentage sales by activity | Form of regulation |
|---|---|---|---|---|
| **Distribution** | | | | |
| Viridian Group Plc | Viridian Group distributes and supplies electricity in Northern Ireland. | Domestic 100% | Electricity: 88%<br>Other: 12% | Price cap |
| Bewag AG | Bewag AG supplies the city of Berlin with electricity, steam generated district heating and street lighting. Bewag is Western Europe's biggest distributor of district heating. | N/a | Electricity: 77%<br>Other: 23% | Competitive |
| Dedasz Rt. | Dedasz Rt. supplies electricity to the South-Western region of Hungary. Activities include the purchase, distribution and sale of electricity and the construction and maintenance of electric networks. | N/a | Electricity: 97%<br>Other 3% | |
| **Transmission** | | | | |
| Delmagyarorszagi Aramszolgaltato Rt | Demasz Rt is majority owned by Electricite de France. It has exclusive license to distribute electricity to southeastern Hungary. | N/a | Electricity 97%<br>Other 3% | |
| National Grid Group Plc | National Grid is a leading operator of electricity distribution and transmission networks in the UK and the US and is also developing telecoms businesses in Brazil, Chile, Argentina and Poland. | Europe 98%<br>Rest of the World 2% | Transmission 76%<br>Other 24% | Price cap |
| Red Electrica de Espana | Red Electrica de Espana is Spain's electricity grid operator. Its main activity is the transmisión of electricity in Spain and operation of the grid. | Domestic 92%<br>International 8% | Energy/power 41%<br>Services 59% | Price cap |

| Company | Brief description | Percentage sales by geographical region | Percentage sales by activity | Form of regulation |
|---|---|---|---|---|
| **Generation** | | | | |
| Powergen Plc | Powergen is an integrated international utility with operations focused around the UK and the US. | Domestic 98%<br>International 2% | Electricity 96%<br>Other 4% | Competitive |
| **Integrated electricity companies** | | | | |
| Endesa SA | Endesa is the largest Spanish electricity company and has significant Latin American presence. Endesa is also active in telecoms. | Domestic 69%<br>International 31% | N/a | |
| Iberdrola SA | Iberdrola is the second largest electricity company in Spain, and is present in Latin America in both electricity and telecoms. | N/a | | |
| Hidroelectrica Del Cantábrico | Hidroeléctrica is the smallest of the Spanish independent electricity companies. | N/a | Energy 81%<br>Other 19% | |
| Union Electrica Fenosa SA | Union Electrica Fenosa SA produces, transmits, and markets electricity. Also designs, develops and operates architectural and civil engineering projects mainly related to water supply and waste treatment. | Domestic 89%<br>Inetrnational 11% | N/a | |
| Scottish & Southern Energy Plc | Scottish and Southern is vertically integrated with its core business being generation, transmission, distribution and supply business in norther Scotland and distribution and supply of electricity in the south of England. | Domestic 100% | Electricity sales 91%<br>Other 9% | |

| Company | Brief description | Percentage sales by geographical region | Percentage sales by activity | Form of regulation |
|---|---|---|---|---|
| Enel SpA | Enel is the world's largest quoted utility and is Italy's dominant integrated utility and dominant electricity company. Its key activities include transmission, generation, distribution, telecoms and water. | N/a | Electricity: 100% | |
| Electricidade de Portugal SA | EDP is the dominant electricity company in Portugal and is also expanding into,multi-utilities, mainly gas and water. | Domestic 98.5%<br>International 1.5% | Electricity: 97%<br>Other 3% | |
| Sondel - Societa Nordelettrica SpA | Sondel provides electricity and operates steam power generating companies | N/a | Electric energy 91%<br>Other 9% | Competitive - with threshold |
| Vorarlberger Kraftwerke AG | Vorarlberger Kraftwerke AG generates and distributes electricity and offers power plant, waterway and sewage treatment plant construction services. | Domestic: 79%<br>International: 21% | Electric generation and supply 92%<br>Other 8% | Cost-plus, administratively set |
| Oesterreichische Elektrizitaetswirtschafts AG | Verbund generates about half of Austria's electricity consumption, and supplies the RECs. The company has moved downstream over the past few years via acquisitions. | Domestic: 87%<br>International: 13% | Electricity: 97%<br>Other: 3% | Cost-plus, administratively set |
| Energieversor Oberfranken AG | | | | |
| EVN AG | EVN is one of nine Austrian RECs (by far the largest), supplying electricity and gas to the province of Lower Austria. | Domestic: 97.5%<br>International: 2.5% | Energy: 73%<br>Other: 27% | Cost-plus, administratively set |
| Sydkraft AB | Sydkraft generates, sells and distributes electricity in southern Sweden, central Norrland and the Stockholm area and sells natural gas and LPG in southern Sweden. | N/a | Electricity: 80%<br>Other 20% | |
| ELMU Rt. | Elmu is a regional electricity distributor and provides electricity to the city of Budapest and 12 cities and 116 villages around Budapest. | N/a | Electric Power 97%<br>Other 3% | Price cap - ministerial supervision |

| Company | Brief description | Percentage sales by geographical region | Percentage sales by activity | Form of regulation |
|---|---|---|---|---|
| **European Multi-utilities** | | | | |
| Edison SPA | Edison is Italy's leading independent power producer and the leading private gas distributor and has also diversified into telecoms through subsidiaries. | Domestic: 99.8%<br>International 0.2% | Electric Power 86%<br>Other 14% | |
| AEM SpA | AEM is an integrated municipal utility, serving the Milan area, operating in electricity, gas distribution and recently also in telecoms. | N/a | Electricity: 37%<br>Other: 63% | |
| ACEA SpA | ACEA is a multi-utility supply water and electricity in the Rome area. It operates an integrated electricity business, and as a result of recent acquisitions, it is now active in water and telecoms businesses. | N/a | Electricity: 51%<br>Other: 49% | |
| RWE AG | RWE is the biggest of the three German diversified utilities. Its core business is in energy and power, but holds strong positions in the water business. | Domestic: 79%<br>International: 21% | Electricity: 32%<br>Other: 68% | Competitive |
| Neckarwerke Stuttgart AG | Neckarwerke Stuttgart generates, transmits and distributes electricity, and provides district heating services to cities and municipalities in the state of Baden-Wuerttemberg. | Domestic 100% | Electricity 67%<br>Other 33% | |
| Scottish Power Plc | Scottish Power is the UK's largest multi-utiltiy. It generates, transmits, supplies and distributes electricity in Scotland and England as well as own Scottish Water and retails gas and telecoms. | Domestic: 83%<br>International: 17% | Energy and power 67%<br>Other 33% | |
| Electrabel | Electrabel is the largest power and gas supplier in Belgium, and also distributes cable TV and in some areas water. | Domestic: 100% | Electricity: 75%<br>Other: 25% | Cost-plus, administratively set |

*Source: www.corporateinformation.com; NERA analysis of Bloomberg data*

**Table C.2**
**Analysis of risk-free rates**

| Bond type | Issue date | Current yield | Average yield to maturity: Arithmetic mean | Average yield to maturity: Geometric mean |
|---|---|---|---|---|
| **Portugal** | | | | |
| Oblig do tes medio prazo 5.85% 20/05/2010 | 20/01/2000 | 5.15% | 5.55% | 5.54% |
| **England & Wales** | | | | |
| Treasury 5.5% 2008/12 | 5/10/1960 | 5.07% | 7.21% | 7.05% |
| Treasury 7.75% 2012/15 | 26/12/1972 | 5.32% | 7.45% | 7.31% |
| Average | | 5.20% | 7.33% | 7.18% |
| Treasury 6% 2028 | 21/1/1998 | 4.34% | 4.75% | 4.72% |
| Treasury 4.125% 2032 | 25/5/2000 | 4.32% | 4.37% | 4.37% |
| Average | | 4.33% | 4.56% | 4.55% |
| **Germany** | | | | |
| Bundesrep. Deutschland 8.375% 21/05/2001 | 19/05/1991 | 4.60% | 5.65% | 5.42% |
| Bundesrep. Deutschland 8.25% 11/10/2001 | 20/09/2001 | 4.50% | 5.59%% | 5.39% |
| Average | | 4.55% | 5.62% | 5.41% |
| Bundesrep. Deutschland 6% 20/06/2016 | 20/10/1986 | 5.02% | 6.79% | 6.69% |
| Bundesrep. Deutschland 5.625% 20/09/2016 | 20/09/1986 | 5.06% | 6.82% | 6.74% |
| Average | | 5.04% | 6.81% | 6.72% |
| **US** | | | | |
| Treasury 7.5% 2001 | 15/11/1991 | 4.80% | 6.19% | 6.14% |
| Treasury 7.75% 2001 | 15/02/1991 | 5.10% | 6.27% | 6.21% |
| Treasury 7.875% 2001 | 15/08/1991 | 4.83% | 6.21% | 6.16% |
| Treasury 8% 2001 | 15/05/1991 | 4.96% | 6.24% | 6.19% |
| Average | | 4.93% | 6.23% | 6.17% |
| Treasury 9.125% 2009 | 15/05/1979 | 7.13% | 7.78% | 7.74% |
| Treasury 10.375% 2009 | 15/11/1979 | 7.52% | 8.00% | 7.96% |
| Treasury 10% 2010 | 15/05/1980 | 7.18% | 7.89% | 7.84% |
| Treasury 11.75% 2010 | 15/02/1980 | 7.94% | 8.20% | 8.16% |
| Treasury 12.75% 2010 | 17/11/1980 | 7.95% | 8.26% | 8.22% |
| Treasury 13.875% 2011 | 15/05/1981 | 8.05% | 8.32% | 8.29% |
| Treasury 14% 2011 | 16/11/1981 | 7.87% | 8.27% | 8.23% |
| Average | | 7.66% | 8.10% | 8.06% |

*Source: NERA analysis of Bloomberg data.*