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Smart Metering for Electricity Consumers in Selected Jurisdictions

A Report for the AEMC

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1. Introduction

NERA has been commissioned by the Australian Energy Market Commission (AEMC) to write a factual report reviewing the arrangements that have been adopted in relation to Advanced Metering Infrastructure (AMI) in a number of markets. In some countries, AMI is called "smart metering" or "advanced metering systems" (AMS), and occasionally use the country-specific term when describing actual experience. All these systems describe a method of providing time-differentiated information on energy usage to consumers and others. The specification of the system varies by technology and degree of detail from country to country.

1.1. The Coverage of this Report

In this report we describe the AMI arrangements in the following markets in particular:

§ UK (Chapter 2);

§ Italy (Chapter 3);

§ Netherlands (Chapter 4);

§ Sweden (Chapter 5);

§ California (Chapter 6);

§ New York (Chapter 7); and

§ Ontario (Chapter 8).

For each market, we answer a number of questions that have been grouped together where suitable. The questions are listed below.

Energy Market Background

1. Are energy businesses (generation, retail, networks) privately or state owned or controlled?
2. What is the extent of vertical integration in the market between (1) generation, wholesale trading and retailing (2) generation/wholesale and transmission networks and (3) retailing and distribution networks?
3. How many distribution networks are in the market?
4. Are retail markets for electricity (and gas, if applicable) open to competition, for some customers or all (if some, which)?
5. How many retailers are in the market? Do they serve the whole retail market in this jurisdiction or just part of it (e.g. some customer groups, some areas only)?
6. What are the entry conditions of the retail market and other relevant markets?

Cont./….

Policy of Government/regulatory authorities

7. What is the policy of the Government and/or the regulatory authority in relation to AMI?
8. Are there any laws/decrees or other provisions that concern AMI? Can you provide a brief summary of their content?
9. What is the nature or extent of regulatory intervention in AMI arrangements?
10. Have regulatory authorities mandated the deployment of AMI or left it to the market? Who is directly paying for AMI?
11. Have regulatory authorities enacted specific regulatory provisions to mandate, facilitate or incentivise the deployment of AMI?
12. Are there any regulatory or industry statements of technical requirements concerning AMI?
13. Where there has been a mandatory deployment, what has been the time frame and any other requirements for the deployment of AMI? What requirements were included in the laws or regulations used to mandate the AMI rollout?
14. How and over what time frame are the costs of AMI services being recouped (i.e. either a regulatory depreciation period or a commercial expectation)?

Roles of Market Players

15. What are the roles and responsibilities of (1) distributors; (2) retailers or (3) intermediaries and the extent to which each has been primarily or solely responsible for AMI arrangements?
16. Who owns the meters and communication infrastructure?
17. Who installs the meters?
18. Who maintains the meters?
19. Who operates the communication infrastructure?
20. Who provides, accesses and processes data?
21. Who are the parties involved in these services and on what basis have the roles been allocated between the parties involved in AMI services?
22. If applicable, how is interoperability between different AMI services and between different operators/providers ensured?

Progress to Date

23. What has been the progress to date?
24. When and where were policies set out? When did the implementation of the policy begin, if at all?
25. What is the extent of AMI penetration?
26. What proportion of customers and, in particular, of residential customers have received smart meters?

1.2. Summary of Findings

The seven jurisdictions that we have been asked to review exhibit different approaches towards setting the functionality of smart meters, the type of communication and data management infrastructure. The key points that we observed in these cases are summarised below.

Some similarities also emerge. The motivation for the introduction of AMI has been largely a desire to provide electricity and, in some cases, gas customers with information to help them make more informed decisions about their energy use. Delays in implementation derive from concern over costs (relative to benefits) or a desire to coordinate the choice of technology or the functionality of the AMI.

1.2.1. United Kingdom

In the UK, the provision and operation of metering are both open to competition. Energy suppliers are responsible for appointing meter operators (on behalf of their customers).[1] The electricity wholesale market rules require generators, network interfaces (i.e. connections between transmission and distribution networks) and large customers to have half-hourly meters that suppliers can read remotely.

The UK Government has considered mandating smart meters for small retail customers, in part to comply with the EU requirements for more detailed billing under the EU Energy Service Directive (2006/32/EC). The Government recently expressed an “expectation” that all gas and electricity customers would receive smart meters by 2017. However, it has since decided to delay a decision on whether to mandate a roll-out to all small and domestic customers and is currently only proposing to mandate a pilot roll-out to about 200,000 large gas and electricity consumers. As yet the Government has not committed to any strategy for rolling out smart meters to all small and domestic retail consumers. The Government has indicated that interoperability between installed technologies would be a prerequisite to any mandatory roll-out of smart metering.

Progress on the installation of smart meters for retail customers has been minimal to date, and any smart meters that are currently installed at small retail consumers’ premises have been installed within a competitive framework.

1.2.2. Italy

The Aeeg (Italian energy regulator) has instigated the installation of smart meters by distribution networks for all electricity customers. The roll-out of smart meters was aimed at achieving the policy objective of introducing time-of-use tariffs, in order to promote more efficient patterns of consumption.

AMI for retail customers is being rolled out by distribution networks and the program is more or less on schedule for completion within the next three or four years. Enel, the largest of the distribution networks, has to date has installed smart meters for over 30 million customers.

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[1] This decision was intended, we believe, to minimise obstacles to customer switching. In practice, energy suppliers who acquire a new customer have tended to take over the customer’s existing meters, rather than to install a new one.

1.2.3. Netherlands

On 4 March 2008, the Minister of Economic Affairs issued a draft law that would require Dutch distribution networks to install AMI for all end users of electricity and gas within six years from 2009. The costs would be covered by the networks' regulated tariffs for metering services. The Government proposes to standardise AMI to facilitate its use by distribution networks and suppliers. The standards are to be reviewed every three years to keep up with the latest software developments.

Currently, smart meters are only offered to electricity consumers by one independent retailer.

1.2.4. Sweden

The Swedish Government has imposed an obligation on distribution networks to undertake monthly meter readings for most customers and hourly meter readings for large customers (> 63 Amp). These obligations, while not mandating smart metering, require, *de facto* the installation of AMI. No technical specifications for AMI have been set out yet, although because distribution networks have an obligation to provide metering data to others, the industry has agreed a common data format. The distributors expect to have installed AMI for 94% of customers by 2009.

1.2.5. California

In 2004, the energy regulator California Public Utilities Commission (CPUC) ordered the three investor-owned utilities (IOUs), each to file plans for the implementation of AMI as part of their energy efficiency programmes. The IOUs each have a local monopoly over distribution and retailing of electricity in their areas which represent 68 per cent the state's load and 80% of transmission capacity. Retail competition (known as direct access) was suspended by the CPUC in 2001 following the energy crisis in California. The regulatory discussion of AMI requirements applies to both electricity and gas markets.

The filings from the two IOUs are still awaiting final approval by the CPUC. PG&E received approval for its full AMI deployment funding but the IOU has postponed deployment activities. At present the implementation of AMI is limited to test cases. Two municipal utilities (SMUD and LADWP) have begun to implement advanced systems for remote meter reading.

Funding of the IOUs deployment plans will initially be funded from higher regulated revenues to be passed onto customers. However, some utilities have indicated that they believe that the resulting operational savings and demand response will exceed the cost over the life of the AMI programs.

1.2.6. New York

In 2007, the then governor of New York announced a commitment to introduce smart metering. The aim was to provide customers with information to help them conserve energy. The New York Public Services Commission or PSC (the energy regulatory commission) formally requested electric utilities to file plans for the development and deployment of AMI programs – where it would be feasible and cost effective to do so. Those plans revealed differences in understanding as to the role and nature of AMI. The PSC is now consulting on technical specifications for AMI and other matters.

1.2.7. Ontario

Installation of AMI has been on the agenda in Ontario since 1998 and over 1 million smart meters have been installed so far within the province. The local distribution companies are responsible for installation, operation, and maintenance of AMI meters, but the system operator (IESO) is responsible for the technology of meter data management and meter reading. The coordinating role of IESO in the AMI programme was recently strengthened.

The Ministry of Energy established the minimum functionality standards for meters, the meter data management and meter data repository, and the target for meter installations. The Smart Metering Initiative is funded through surcharges on electricity bills designed to compensate distributors for approved activities. By May 2008, 1.27 million meters had been installed in Ontario (covering 25% of the low volume electricity consumers).

1.3. Conclusion

The examples in this report describe a wide range of methods of implementing AMI. Several have yet to proceed beyond the phase of discussions and design, whereas some (e.g. Italy and Ontario) have moved forward with the actual roll-out of AMI. Key factors in the speed of implementation include the requirement to establish the desirability of AMI programmes, time taken to coordinate technologies and different methods adopted for cost recovery. However, each of the examples shows that roll-out of AMI is likely to take many years.

2. UK

2.1. British Energy Market Background

2.1.1. Overview of sector structure

1. **Are energy businesses (generation, retail, networks) privately or state owned or controlled?**
2. **What is the extent of vertical integration in the market between (1) generation, wholesale trading and retailing (2) generation/wholesale and transmission networks and (3) retailing and distribution networks?**
3. **How many distribution networks are in the market?**
4. **How many retailers are in the market? Do they serve the whole retail market in this jurisdiction or just part of it (e.g. some customer groups, some areas only)?**

§ Generation and Supply

The majority of the British electricity and gas industries were privatised during the 1980s and 1990s. The only electricity assets that are controlled by the British Government consist of around 1.5GW of nuclear generation plants owned by the state-owned company British Nuclear Fuels Limited (out of total installed capacity of around 80GW).[2] All electricity and gas network and supply (i.e. retail) businesses are privately controlled.

The British electricity industry is highly vertically integrated, with the six largest companies holding majority market shares in both retail and generation, as Table 2.1 illustrates. Since May 1999, all customer types have been able to choose their electricity supplier, and as Table 2.1 also shows, the six large suppliers serve the majority of all market segments, with a combined market share of close to 100% in the domestic segment. In addition to the six large vertically integrated companies, a number of smaller suppliers that are not active in the domestic market segment serve non-domestic consumers.

§ Networks

There are three electricity transmission networks in Great Britain. Two of the large vertically integrated players (Scottish Power and Scottish and Southern Energy) each own one of the three transmission networks, although the transmission system operator for the whole of Britain is National Grid, which has no UK generation or supply interests. National Grid owns the third (and largest) transmission network, in England and Wales. It also owns the single British gas transmission network.

Four of the six large vertically integrated players also own British electricity distribution networks. There are fourteen such networks in total, and the six large vertically integrated firms own nine of them, as Table 2.2 indicates. Since 1999 electricity distribution and supply have been separately licensed activities, and distribution networks and supply businesses have licence requirements that impose separation between the two business functions where

[2] Capacity data from Platts Powervision.

there is common ownership. In total, seven companies own the fourteen British electricity distribution networks, with ownership per company ranging from one to three networks.

Six of the eight British gas distribution networks are owned by companies without supply interests. Scotia Gas Networks, in which the vertically-integrated Scottish and Southern Energy holds a 50% stake, owns the other two gas distribution networks.

As far as we are aware, all gas and electricity supply companies offer supply tariffs to consumers in all geographic areas of Great Britain.

Table 2.1.
Generation and Supply Market Shares

	Market Shares			
	Generation Capacity	Domestic Electricity Supply	Non-Domestic Electricity Supply (<100kW Consumption)	Non-Domestic Electricity Supply (>100kW Consumption)
British Energy	15%			18%
E.ON	13%	19%	19%	11%
SSE	13%	18%	16%	12%
RWE	12%	16%	17%	17%
ScottishPower	8%	12%	7%	5%
EDF	7%	14%	18%	19%
Drax	5%			
Centrica	4%	22%	17%	-
BNFL	3%			
AIG Highstar	3%			
International Power	4%			
Others	12%		6%	18%
Total	100%	100%	100%	100%

Source: Ofgem 2007 Report to ERGEG[3]

Table 2.2.
Overview of British Electricity Distribution Networks

	Customers ('000s)	Share (%)
CE Electric UK - North East	1,540	5%
CE Electric UK - Yorkshire	2,212	8%
Central Networks East (E.ON)	2,529	9%
Central Networks West (E.ON)	2,407	8%
EDF - Eastern	3,437	12%
EDF - London	2,193	8%
EDF - South East	2,210	8%
Scottish Power	1,954	7%
Manweb (Scottish Power)	1,459	5%
SSE Hydro (North Scotland)	709	3%
SSE Southern	2,819	10%
Electricity North West	2,332	8%
Western Power Distribution (South Wales)	1,070	4%
Western Power Distribution (South West)	1,489	5%
Total	28,360	100%

3 Note, a zero market share in the supply columns does not necessarily mean that the company has no supply interest. Its supply interests may be included in the "others" category.

2.1.2. Status of retail and metering competition

5. Are retail markets for electricity (and gas, if applicable) open to competition, for some customers or all (if some, which)?

6. What are the entry conditions of the retail market and other relevant markets?

All segments of the British gas and electricity retail markets are open to competition. Metering services are also open to competition (i.e. they are "contestable"). Parties wishing to enter the supply market must be licensed by the industry regulator Ofgem. In addition to complying with their licence, suppliers must adhere to a number of industry codes and agreements to operate in the market.

Ofgem occasionally surveys the retail market and publishes data on market shares in electricity supply to small residential ("domestic") customers. The following tables come from an Ofgem report on the domestic retail market published in July 2007.[4]

Table 2.3:
National Market Shares in Electricity (up to March 2007)

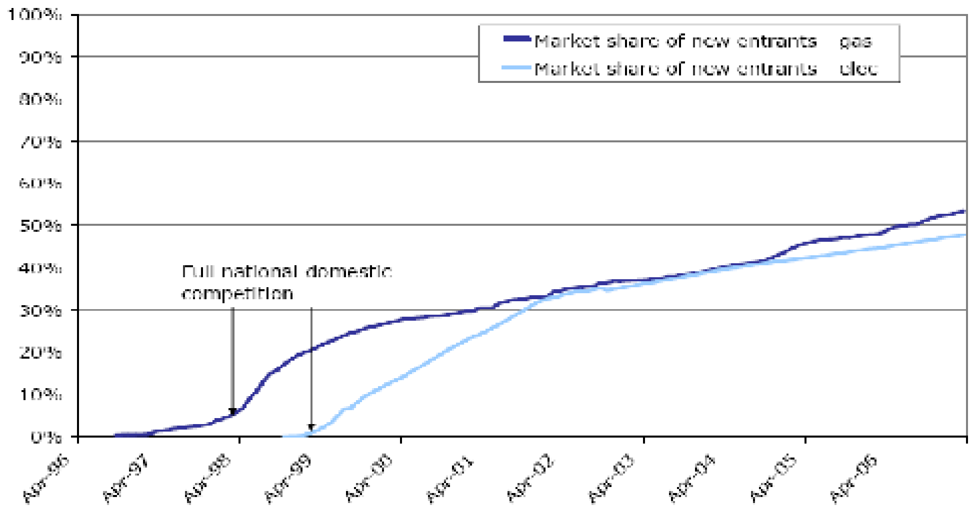
Group	Dec-02	Jun-03	Dec-03	Jun-04	Dec-04	Jun-05	Mar-06	Mar-07
BGT	22%	23%	24%	24%	23%	22%	22%	22%
Powergen	22%	22%	21%	21%	21%	21%	20%	19%
SSE	13%	14%	14%	15%	15%	16%	16%	18%
npower	16%	16%	15%	15%	15%	15%	15%	16%
EDF Energy	15%	15%	14%	14%	13%	13%	13%	14%
ScottishPowe	10%	10%	11%	12%	13%	13%	13%	12%
Others	0%	1%	1%	0%	0%	1%	0%	0%

Table 2.4:
National Market Shares in Gas (up to March 2007)

Group	Dec-02	Jun-03	Dec-03	Jun-04	Dec-04	Jun-05	Mar-06	Mar-07
BGT	63%	62%	61%	59%	57%	53%	52%	47%
Powergen	12%	12%	12%	12%	13%	14%	13%	13%
SSE	6%	6%	7%	8%	8%	9%	10%	13%
npower	9%	9%	9%	9%	9%	9%	10%	12%
ScottishPowe	5%	5%	6%	7%	8%	9%	9%	9%
EDF Energy	5%	5%	5%	5%	5%	5%	6%	7%
Others	0%	0%	1%	0%	0%	0%	0%	0%

4 Ofgem (2007), Domestic Retail Market Report - June 2007, 169/07. 4 July 2007, pages 22-23.

Figure 2.1:
Market Shares of New Entrants Since Liberalisation[5]



Ofgem has also extended competition into metering. Metering services in Great Britain are divided into two functions: (1) the provision (or ownership) of meters by a Meter Asset Provider (MAP), and (2) the installation, commissioning, testing, repair, maintenance, removal and replacement of electricity metering equipment, by a Meter Operator (MOp). There is a third separate function for "meter reading and data services" (i.e. the gathering and processing of metering data), which is the responsibility of suppliers. Under the electricity industry rules, suppliers must nominate a party to aggregate metering data for submission to the settlement company, Elexon.[6]

The new distribution licences issued following the separation of the distribution and supply functions in 1999 required distribution networks to act as the MAP and MOp to any supplier operating in their area on request, but this requirement was removed in 2007.[7] Distribution networks' Standard Licence Condition (SLC) 36 now requires that "in-area" distribution networks act as the MAP to all suppliers for non half-hourly meters that were installed before 31 March 2007. This role is known as Legacy Basic Meter Asset Provision. Hence, although distribution networks currently own a large proportion of the meters that are installed on their networks, as suppliers replace older meters, the proportion of distribution network-owned meters will fall. Ofgem caps the tariffs that distribution networks can charge for legacy meter services.

Hence, suppliers must appoint Meter Asset Providers and Meter Asset Managers (MAMs), which are usually the same company, respectively to provide their MAP and MOp services. Suppliers can still contract with distribution networks for metering services, but increasingly suppliers are choosing to contract with competitive suppliers of metering services.

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5 Ofgem (2007) Fig 7.1 page 23.

6 For definitions of metering functions, see: Domestic Metering Innovation - Next Steps, Ofgem (107/06), 30 June 2006, Appendix 6 (Glossary).

7 Electricity Industry Review 11, Electrica Services Ltd, June 2007.

2.2. Government Policy

7. What is the policy of the Government and/or the regulatory authority in relation to AMI?

2.2.1. Government Policy on Smart Metering

In May 2007, the UK Government published a wide-ranging review of energy policy in its "Energy White Paper". Following consultations on the policies set out in this document, the Government is now in the process of implementing the majority of the White Paper proposals through the 2008 Energy Bill. However, the final decision to implement these policies depends on the transition of the Bill through the two Houses of Parliament.

Amongst the proposals in the White Paper were the Government's new policies regarding "smart metering" and the provision to energy users of real-time display devices that display energy usage. The Government proposed in the White Paper that it would require electricity suppliers to provide real-time display units to domestic consumers on a new and replacement basis, or on request from consumers, in advance of any rollout of smart meters. However, this proposal met with criticism from the industry and Ofgem (the industry regulator) that it would result in wasteful investment, distract from the smart meter rollout and undermine the business case for smart meters.[8] The Government has since decided not to require suppliers to provide stand-alone real-time display devices, although it is still attempting to reach a voluntary agreement with suppliers for the deployment of these devices.[9]

In the White Paper, the Government also expressed an "expectation" that, over the next ten years, all gas and electricity customers will be given smart meters (defined as interval meters allowing two-way communication between the supplier and customer) with separate visual displays.[10] However, as we discuss below, it is only proposing to mandate a smart meter rollout for certain groups of customers.

One driving force behind the Government's desire to promote the uptake of smart metering technologies is its need to transpose the EU Energy Services Directive (2006/32/EC) into British law. According to the Government, the key requirements of the Directive concerning metering are that:

§ "in so far as is 'technically possible, financially reasonable and proportionate in relation to the potential energy savings', final customers for electricity, natural gas, district heating/cooling and domestic hot water are provided with competitively priced, individual meters that accurately reflect the customer's actual energy consumption and provide information on actual time of use; and

8 Ofgem Response to BERR Energy Billing and Metering: Changing Consumer Behaviour consultation, 31 October 2007, page 9.

9 BERR (2007), Energy Billing And Metering - Changing Consumer Behaviour: A Consultation on Policies Presented in the Energy White Paper, Department for Business, Enterprise and Regulatory Reform, August 2007, para. 2.1; and BERR (2008), Energy Billing And Metering - Changing Customer behaviour: Government response to a consultation, Department for Business, Enterprise and Regulatory Reform, April 2008, para. 3.7-3.8.

10 BERR (2007), para 2.2.

- § when an existing meter is replaced, such competitively priced individual meters should always be provided unless it is 'technically impossible' to do so or it is 'not cost-effective in relation to the estimated potential savings in the long-term'. It also requires that, when a connection is made to a new building, or a building undergoes major renovations, such competitively priced individual meters should always be provided."[11]

The provisos relating to technical feasibility and cost-effectiveness mean that the Directive does not oblige Member States to install AMI. However, the UK Government appears to regard the Directive as an obligation to facilitate or promote AMI where it meets certain conditions.

2.2.2. Government proposals to increase smart meter uptake

8. What is the nature or extent of regulatory intervention in AMI arrangements?

9. Have regulatory authorities mandated the deployment of AMI or left it to the market? Who is directly paying for AMI?

10. Have regulatory authorities enacted specific regulatory provisions to mandate, facilitate or incentivise the deployment of AMI?

11. Are there any laws/decrees or other provisions that concern AMI? Can you provide a brief summary of their content?

Under current electricity market settlement arrangements, half-hourly meters are compulsory for all consumers with a maximum demand of 100kW and above.[12] The Government has proposed requiring suppliers to install electricity smart meters within five years for certain categories of the small and medium energy user (SME) market segment below this threshold, extending compulsory half-hourly metering to a group defined as consumers with: [13]

- § "Maximum Demand" meters that record maximum demand (in kW) in a period, as well as consumption; and
- § An "annual peak load factor" of less than 20%, i.e. total annual consumption is less than 20% of what it would be if the user's maximum demand had been sustained at a constant rate throughout the year.

For gas meters, the Government proposed to set the threshold of consumption at 732,000kWh of gas per annum for the compulsory rollout of smart meters.

In Great Britain as a whole, around 200,000[14] metering points, some of which already have smart meters, fall into these categories.[15] The Government plans to mandate the rollout of smart meters to consumers above these thresholds through the 2008 Energy Bill.[16] The

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[11] BERR (2008), Annex A.

[12] ELEXON Response to BERR Consultation on Energy Billing and Metering, 29 October 2007, page 2.

[13] BERR (2007), para 2.2; and Load profiles and their use in electricity settlement, Elexon (undated).

[14] BERR (2007), para 7.6.

[15] BERR (2008), para 4.1.

[16] BERR (2008), para 4.16.

Government has not yet set out its policy regarding the rollout of smart meters to domestic and small business premises. However, in its cost-benefit analysis of the different methods for rolling out smart meters to domestic and small business premises, it identified the following options:[17]

- No domestic smart metering mandate but a better billing and displays policy;
- Mandated new and replacement rollout of smart meters within existing market structures, i.e. requiring individual suppliers to arrange for installing smart meters and the associated communications infrastructure;
- Mandated 10-year roll out of smart meters in a regional franchise market model;
- Mandated 10-year rollout requiring individual suppliers to arrange for installing smart meters and the associated communications infrastructure;
- Mandated 10-year rollout, requiring individual suppliers to arrange for installing smart meters, but appointing a separate body to install and operate the meters once they are installed, and to set up and operate the associated communications infrastructure; and
- An indirect mandate, whereby the Government would, for instance, not require suppliers to install smart meters, but require them to provide accurate monthly bills within a certain timeframe, which would in effect necessitate a smart meter rollout to all consumers.

We outline these proposals in more detail in section 2.3.1 below. The Government has not stated which of the rollout methods it is most likely to adopt, although the industry regulator, Ofgem, has stated its preference for rolling out smart meters within existing industry arrangements[18] (i.e. making individual suppliers responsible for arranging the deployment to their customers), whereas most of the major suppliers would prefer a regional franchise approach:

> "An alternative view expressed by most of the major energy suppliers was that the current market structure would not enable the rapid deployment of smart meters and some form of managed and coordinated roll-out would be required…The major suppliers proposed a 'regional franchise model' whereby roll-out proceeded on a geographical basis under the management of a regional franchisee."[19]

2.2.3. Legislative and regulatory provisions for the smart meter rollout

As noted above, metering is a competitive segment of the gas and electricity industries, with suppliers having the ultimate responsibility for replacing and maintaining meters, even if they contract out these activities. The electricity market rules require that the suppliers of the largest electricity users install half-hourly meters, which must be connected to a communications network to allow remote automatic meter reading.[20] Similarly, the gas

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[17] See section 2.3.1 for more details on these options.

[18] BERR (2008), para. 7.6.

[19] BERR (2008), para. 7.7-7.8.

[20] Elexon Automatic Meter Reading Factsheet, 27 May 2007.

market rules require all users with annual consumption above a certain threshold to have daily-read meters, which are capable of being read remotely.

For all other categories of consumers, there has not yet been a Governmental or regulatory mandate to install smart meters. For consumers with consumption below the threshold for compulsory half-hourly or daily metering, the decision over whether to install smart meters has so far been left to the market. Where smart meters are installed, the supplier and/or the consumer must pay for the installation and maintenance of the meter.

Although there has been no Government mandate to install smart meters for smaller energy-users, as described above, the Government plans through the 2008 Energy Bill to lower the thresholds above which smart meters will be compulsory. Although, this mandate will not extend to domestic consumers and small business consumers, the Government intends that the bill will grant it the power to extend further these thresholds if it can make a case for doing so. Specifically, the Government expects that the Energy Bill will grant it the right to amend electricity and gas licences in order to mandate the introduction of smart meters to larger energy consumers, although we understand that the Bill will allow the Government flexibility regarding which parties (i.e. suppliers or distribution networks) would be mandated to roll out smart meters:

> "The new power will allow the Secretary of State to modify electricity distribution and supply licences and gas transporter, shipper and supply licences… to require the licence holder to install, or facilitate the installation of, smart meters."[21]

2.2.4. Required smart meter functionality

12. Are there any regulatory or industry statements of technical requirements concerning AMI?

The Government defines a smart meter as "an interval meter allowing two-way communication between the energy supplier and the customer".[22] The Government has as yet not set out detailed technical requirements of the meters that it will require suppliers to install following the proposed changes to supply licences (i.e. for larger energy users). We expect the required specifications of the meters to emerge following the ascension of the 2008 Energy Bill into law.

Regarding the functionality of smart meters for domestic and small business consumers, the Government has yet to decide on the functionality it would require if it mandates a nationwide rollout, stating that "further impact assessment work and consultation is needed to understand the attribution of benefits across technologies before making a final decision".[23] It has indicated that, whatever the choice of functionality, interoperability between installed technologies would be prerequisite to any smart meter rollout (see section 2.3.4).

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21 Energy Bill Explanatory Notes, referring to the Energy Bill brought from the House of Commons on 1st May 2008 [HL Bill 52], www.partiament.uk, para. 432.

22 BERR (2007), para. 7.3.

23 BERR (2008), para. 7.14.

The industry association of British energy retailers, the Energy Retail Association (ERA), has been leading efforts to develop minimum operational requirements for British domestic smart meters, in advance of any future Government mandate for a nationwide rollout, through the Supplier Requirements for Smart Metering (SRSM) project. The ERA has also developed an "operational framework", which it intends will create an interoperable platform for gas and electricity smart meters so all suppliers can use the installed meters. The functional requirements set out by the ERA's operational framework are as follows:

- Two-way communication with suppliers and the local smart meter communication infrastructure;
- Two-way communication to enable suppliers to configure, monitor and manage the metering system without the need to visit premises;
- Support flexible tariff structures, including time of day, type of day and consumption based profiles for energy consumption.
- Electronic storage and display of data, including tariff and consumption
- Recording of electricity imported from the distribution network, as well as that exported from premises with microgeneration technology installed;
- Functionality to support disconnection and reconnection of supply; and
- The functionality to switch between credit and debit (prepayment and pay-as-you-go) operation.

13. Where there has been a mandatory deployment, what have been the time frame and any other requirements for the deployment of AMI? What requirements were included in the laws or regulations used to mandate the AMI rollout?

Not applicable.

2.2.5. Recovering the costs of smart meters

14. How and over what time frame the costs of AMI services are being recouped (i.e. either a regulatory depreciation period or a commercial expectation)?

At present, recovering the costs of installing meters is left to commercial arrangements between suppliers and customers in all market segments. We have not seen any indication from the Government in its consultations on smart metering that it will change these arrangements for the mandated rollout of smart meters to the larger energy users. In the consultations on a wider smart meter rollout to smaller commercial and domestic users, the Government has presented a variety of options for rolling out smart meters (see section 2.3.1).

Under one possible approach, suppliers would pay for and/or conduct any rollout of smart meters to small business and domestic users, and so suppliers would seek to recover these costs from consumers and would bear the risk of any under recovery of smart meter rollout costs.

Under other options, the smart meter rollout would be undertaken by regional franchise operators or metering services would be "rebundled" into distribution networks regulated businesses. In these cases, the Government's envisaged arrangements for cost recovery are less clear. In the regional franchise case, we understand that potential franchisees would bid for the right to roll out smart meters. In this case, the costs that franchisees are allowed to recover would be passed through to suppliers, who would then need to recover them from consumers through commercial arrangements.

Under the "rebundling" option, we anticipate that the distribution networks would recover the costs of installing smart meters distribution network charges that they charge to suppliers. Hence, suppliers would still need to recover these costs from consumers through commercial arrangements.

2.3. Roles of Market Players

15. What are the roles and responsibilities of (1) distributors; (2) retailers or (3) intermediaries and the extent to which each has been primarily or solely responsible for AMI arrangements?

16. Who owns the meters and communication infrastructure?

17. Who installs the meters?

18. Who maintains the meters?

19. Who operates the communication infrastructure?

At present, the Government has not decided what roles it would assign to individual parties in the event that it proceeds with a national smart meter rollout, and is considering a number of options regarding which parties would be responsible for rolling out, owning and maintaining the meters and the associated communications infrastructure.

2.3.1. Options regarding the roles of industry players

At present gas and electricity suppliers are ultimately responsible for maintaining, replacing and installing new meters, although they may subcontract to other parties. In the event of a nationwide smart meter rollout to small and domestic consumers, the first option that the Government is considering is a "status quo" approach, whereby it would "require suppliers to provide smart meters with displays over a defined time period with a defined level of functionality. Suppliers would be responsible for contracting for metering services to deliver the Government's mandate."[24]

Another option the Government is considering for rolling out smart meters is a regional franchise model, whereby the winners of regional competitive tenders would roll out smart meters to small businesses and households. In this case, supply companies, distribution networks and other companies could bid for the task of rolling out smart meters in each region, including the associated communications and data infrastructure. The regional franchises would only last for the duration of the initial rollout. It appears that the tenders

[24] BERR (2008b), pages 16-17.

would not cover the meter ownership and management functions, which would remain the responsibility of supply companies.[25] The ERA, representing suppliers, has stated that it prefers the regional franchise approach to rolling out smart meters.[26]

The Government has also considered setting up one national or several regional “infrastructure provider” companies to operate smart meters, and set up and operate the associated communications and data infrastructure. Suppliers would be responsible for installing smart meters which would be linked into the regional (or national) communications infrastructure, thereby allaying potential concerns around interoperability and switching processes.[27]

A further option the Government is consulting on is to conduct the rollout through distribution networks, which would purchase, install and operate smart meters and the associated communications infrastructure.[28] This would involve “rebundling” of metering services into the distribution networks’ regulated businesses. Ofgem does not support this approach, stating that “relying on the commercial incentives of suppliers is the best means of adequately protecting consumers and ensuring that where new metering investment is made, it is cost effective and meets their needs”.[29]

The final option that the Government is considering is an “indirect Government mandate” approach whereby it would require that, within a certain period, suppliers provide customers with “clear and accurate monthly bills”, which in practice would require suppliers to roll out smart meters to their customers.[30] The Government also considered an option where it would implement its proposals for improved information on billing, without rolling out smart meters to small and domestic users. This option constitutes, in the opinion of the Government, the minimum required to comply with the Energy Services Directive.[31]

2.3.2. UK Government Cost-Benefit Analysis

As described above, the Government’s cost-benefit analysis considered a number of options for rolling-out smart meters and the costs of each option. It also considered two types of technology, AMR meters (see above) and AMM meters, which have the same functionality as AMR meters, but allow two-way communication, can measure micro-generation exported to the grid, allow remote disconnection and permit switching between credit tariffs and pre-payment tariffs.[32]

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25 Impact Assessment Presented Energy Bill Amendments on Smart Metering for the Energy Bill, Department for Business Enterprise and Regulatory Reform, April 2008, page 17. (BERR, 2008b)

26 Look Smart Coalition Manifesto, ERA, energywatch, and Utility Week, undated.

27 BERR (2008b), pages 17-18.

28 BERR (2008b), page 17.

29 Domestic Metering Innovation – Next Steps, Ofgem (107/06), 20 June 2006, para. 2.9 and 2.12.

30 BERR (2008b), page 18.

31 BERR (2008b), page 16.

32 BERR (2008b), section E1.

The cost-benefit analysis compared the costs associated with each proposed approach with a set of identified benefits. Of the benefits it identified, it quantified the following:[33]

- Supplier benefits:
  - Lower costs for meter reading, call center operations, debt management and customer switching between suppliers;
  - Reduced power theft; and
  - Lower cost of serving prepayment customers.
- Benefits from behavioral changes:
  - Lower energy use, resulting from improved customer information and a response to time-of-use tariffs,
  - Peak load reduction, which reduces network costs; and
  - Reduced scope for disputes between customers and suppliers.

The Government also considered a number of unquantified (i.e. "intangible") benefits:

- Improved data and information from smart meters will facilitate switching and so could improve competition;
- The use of demand side load shifting may provide longer-term benefits for network management;
- Increased data on consumption could enable better targeting of fuel poverty resources and assist suppliers in reducing their customers' energy use; and
- The increased potential for load shifting could reduce the cost of accommodating increased volumes of renewable generation on the grid.

Although the cost-benefit analysis presents estimates of the net present value of costs and benefits of the options considered,[34] it stops short of drawing firm conclusions on the case for a smart meter roll-out. It suggests that further work is required to develop the analysis, in particular to conduct further analysis and consult with stakeholders on:[35]

- Treatment of risk within the economic analysis;
- Assessment of market structures;
- Attribution of benefits to technology functionality;
- Communications options and structures; and
- Further work on smart metering for small businesses.

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[33] BERR (2008b), section E2.

[34] BERR (2008b), section E7.

[35] BERR (2008b), section H.

2.3.3. Options for the communications infrastructure

Regarding the communication system(s) that would emerge following any nationwide rollout of smart meters, the Government has stated that it will leave it to the industry to decide what communication infrastructure should be installed.[36] At present, existing smart meters (principally installed at larger energy users' premises) rely on suppliers' own individual communications networks.

There are several communications networks that the industry rules permit for half-hourly metering in the electricity industry. These include Paknet (radio system), Global System for Mobile Communications (GSM) and Power line Carrier (PLC).[37] We also understand that a number of types of communications systems operate in practice.[38] Under the electricity market rules, the Balancing and Settlement Code (BSC), suppliers must appoint a "Data Collector" and a "Data Aggregator" to collect and submit half-hourly meter data for settlement, which Elexon administers. Elexon is owned by National Grid.[39] It is therefore suppliers' responsibility to arrange for data collection from meters, and to manage the communications method they use to communicate meter readings for settlement.

In the gas industry, we understand that suppliers must submit meter readings for settlement through the UK Link communications system.[40] This system is operated by xoserve, a company that the British gas distribution and transmission networks own jointly.[41]

Regarding the potential future rollout of smart meters to smaller users, Government and regulatory statements on interoperability have focussed on the compatibility of meters for use by different suppliers. In particular, the ERA's publication on interoperability requirements is not prescriptive about the type of communications network that should be used, but suggests all suppliers should use compatible (or the same) infrastructure to avoid the "redundancy throughout the process chain that could potentially be reduced by restricting the number of communications options that are used".[42] The communications infrastructure options that the ERA suggested are:

- Powerline Carrier;
- Fixed Line Telephony;
- Cellular Telephony;
- Short Radio; and
- WiFi/WiMAX.

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36 BERR (2008b), page 28.

37 Automatic Meter Reading, Elexon factsheet, 25 May 2005.

38 NERA email enquiry to Elexon.

39 ELEXON and the introduction of BETTA: Conclusions on the Proposed Modification to NGC's Transmission Licence and Consultation under Section 11A Notice to modify NGC's Transmission Licence, Ofgem, September 2002, para. 4.4.

40 Uniform Network Code, section M.3.3.1.

41 http://www.xoserve.com/about.asp and http://www.xoserve.com/whatwedo.asp

42 Interoperability Requirements, ERA SRSM Project, 19 january 2007, page 8.

It is not yet clear whether the industry, the Government or Ofgem would initiate development of national communications infrastructure that all suppliers can access if the Government were to mandate a nationwide rollout.

2.3.4. Interoperability

20. Who provides, accesses and processes data?

21. Who are the parties involved in these services and on what basis have the roles been allocated between the parties involved in AMI services?

22. If applicable, how is interoperability between different AMI services and between different operators/providers ensured?

For the larger energy users that the Government will require to have a smart meter, it has decided not to set interoperability standards.[43] The industry regulator proposed an argument for this decision:

> "Ofgem said that, as AMR was already being provided in this sector, stranding did not seem to be a significant problem… [and that] whilst interoperability was desirable, the market was operating without formal arrangements, and Government should not impose them."[44]

The Government has stated that if it decides to progress with a smart meter rollout for smaller energy users, it would ask Ofgem to lead industry efforts to set interoperability standards.[45] Ofgem has indicated that it believes the industry should take the lead in developing such standards, and in 2006 it set up an "interoperability working group" to develop them.[46]

2.4. Progress to Date

23. What has been the progress to date?

24. When and where were policies set out? When did the implementation of the policy begin, if at all?

25. What is the extent of AMI penetration?

26. What proportion of customers and, in particular, of residential customers have received smart meters?

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[43] BERR (2008), para. 4.23.

[44] BERR (2008), para. 4.8-4.9. Note that a meter with AMR functionality can store measured electricity consumption data for multiple time periods and provide one-way communications from the meter to allow remote access to that consumption data.

[45] BERR (2008), para. 7.15.

[46] Domestic Metering Innovation – Next Steps, Ofgem (107/06), 30 June 2006, para. 3.6-3.12.

Although there has been a lot of discussion of smart metering (see above), at present, only a very small number of households have smart meters. The only specific information we have found on the extent of domestic smart meter penetration in Britain is the number of consumers who have been provided with smart meters under a Government trail (managed by Ofgem) to study the benefits of smart meters. Under this scheme, the Government announced in 2007 that 15,000 households would receive smart meters.[47]

As noted above, it is already compulsory for larger energy users to have half-hourly or daily meters that are capable of being read remotely. Within five years, the Government plans to extend this requirement to a total of 200,000 consumers.

47 40,000 households in Nationwide energy saving experiment, BERR Press Release, 12 July 2007.

3. Italy

3.1. Italian Energy Market: Background

1. When and where were policies set out? When did the implementation of the policy begin, if at all?

Decision 5/04 of the Authority for Electricity and Gas (Aeeg, "Autorità per l'energia elettrica ed il gas") provided for deployment and use of hourly meters for (1) generators with capacity above 250 kW, (2) extra-high, high and large medium voltage customers by the end of 2004 and (3) for all medium voltage customers by the end of 2006.[48]

The Decision was initially issued in 2004 but has been much revised since then. Given difficulties encountered by many distribution networks in complying with the imposed deadline to complete deployment of hourly meters for medium voltage customers, the deadline was extended to 15 April 2007.

In March 2005, the Aeeg published a consultation document that started a debate on smart meters, remote communication and data metering services in the electricity sector.[49] Although the consultation document was to address the issue of extension of hourly meters to residential customers, it marked the start of a general debate on electricity metering and use of advanced metering infrastructures in the electricity market.

The debate on smart meters is included within the wider plan to differentiate electricity tariffs depending on the day and the time of the day when electricity is used by the consumer. (We will refer to this type of tariffs as the ***"time-of-use tariffs"***.) The deployment of the new electronic meters would allow all final users to choose between a flat tariff and a time-of-use tariff.

With the consultation document published in 2005, Aeeg focused its attention on the new electronic meter as an essential requirement for all customers to use time-of-use tariffs.[50] Such tariffs would allow all customers to respond to price signals and to modify their consumption patterns to achieve savings. The regulator analysed the consumption patterns of a typical residential customer and found that savings from the introduction of time-of-use tariffs could amount to 3%-5% of the electricity bill.

In 2006, Aeeg published a second consultation document in which it reviewed its general approach to the smart metering issue in the 2005 document and underlined the opportunity to

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[48] The Decision number 5/04 is available at the website: http://www.autorita.energia.it/docs/04/005-04all.pdf

[49] The Consultation document, published by Aeeg in March 2005, is available at the website: http://www.autorita.energia.it/docs/dc/05/dc_050307.pdf.

[50] Time-of-use tariffs have been available to wholesale users since 2002 (wholesalers are defined as customers purchasing electricity in order to re-sell it inside or outside their own national system). With the Consultation document of 2005,the regulator aimed at further extend its use to final users (final users are defined as customers purchasing electricity entirely for his/her own use).

extend the use of the electronic meters to all low voltage users and to introduce advanced systems for their remote reading (*telelettura*) and control (*telegestione*).[51]

In the second consultation document, the regulator reiterates the opportunity to offer time-of-use tariffs to all final customers and underlines the importance of smart meters in enhancing competition in the energy market. Its rationale is that a well informed customer has the opportunity to choose the energy supply that best suits her/his need and lower her/his energy bill.

At the end of 2006, the regulator published Decision 292/06, later modified by Decision 235/07, containing final provisions on the deployment and the use of smart meters to low voltage customers.[52]

This Decision, and its consequences for the Italian electricity metering market, are explained and discussed in following paragraphs.

3.2. Overview of Sector Structure

2. **Are energy businesses (generation, retail, networks) privately or state owned or controlled?**
3. **How many distribution networks are in the market?**
4. **What is the extent of vertical integration in the market between (1) generation, wholesale trading and retailing (2) generation/wholesale and transmission networks and (3) retailing and distribution networks?**

According to Legislative Decree number 79/99, which transposed into Italian Law the first EU Directive on the internal electricity market, the generation, import, export, purchase and sales of electricity are all open to competition.[53] Electricity transmission and distribution remain regulated.

Legislative Decree 79/99 also provided for *unbundling* of electricity activities and imposed *legal unbundling* of transmission from all electricity activities and of distribution from sales for those companies serving more than 300,000 end-users.

Such provisions were partially modified by Law 239/04, which lifted the obligation of *legal unbundling* of distribution from sales whilst retaining it as a *possibility*.[54]

In 2007, Law 125/2007 implemented Legislative Decree 79/99 (by opening up the electricity market completely). [55] It provided for legal separation (separate companies) between

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[51] The Consultation document published by Aeeg in July 2006 is available at the following website: http://www.autorita.energia.it/docs/dc/06/dc_060726_23.pdf.

[52] The Decision number 292/06 as updated by the Decision number 235/07 is available at the website: http://www.autorita.energia.it/docs/06/292-06all.pdf.

[53] The Legislative Decree 79/99 is available at the website: http://www.parlamento.it/leggi/deleghe/99079dl.htm.

[54] Law 239/04 is available at the website: http://www.parlamento.it/leggi/04239l.htm.

[55] Law 125/2007, issued on 3 August 2007 and available at http://www.parlamento.it/parlam/leggi/07125l.htm.

electricity distribution and sale for companies serving more than 100,000 customers as of 30 June 2007. Integrated distributors must therefore create new public companies (S.p.A.) to which they must transfer all activities related to sale of electricity.

3.2.1. Generation

Data in Aeeg's last annual report[56] show that the five biggest generators account for about 74% of electricity production. According to the report, the Herfindhal-Hirschman Index for 2006 shows a decrease in market concentration. The following table shows the market share of main generators for 2006 with respect to national electricity production.

Table 3.1
Contribution to the national electricity production from the main operators

Generation company	Percentage
Gruppo Enel	34.8%
Gruppo Edison	13.1%
Gruppo Eni	9.2%
Endesa Italia	8.7%
Edipower	8.3%
Tirreno Power	4.0%
Gruppo Electrabel	1.7%
AEM Milano	1.6%
Gruppo Saras	1.4%
Iride	1.3%
Gruppo ASM Brescia	1.1%
Others	14.8%

Source: NERA calculation from the Aeeg's Annual Report for 2006 issued in July 2007

3.2.2. Transmission

Electricity transmission and despatching are controlled by the state. Transmission is carried out using extra-high voltage and high voltage network. By the end of 2005, ownership of transmission assets and the management of the network had been separated: the owners of the assets were Terna (98%) and other private companies (2%), while the *Gestore della Rete di Trasmissione Nazionale* (GRTN) managed the network.

However, there had been much debate about the benefits of unifying the ownership of the assets and the management of the grid. At the end of 2005, therefore, Terna and GRTN merged, as provided for in Law 290/03,[57] and the new Terna became the Italian Transmission System Operator (TSO). Terna's largest shareholder is the *"Cassa Depositi e Prestiti"* which holds a 29.99% stake.[58]

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[56] The Aeeg's Annual Report published in 2007, available at: http://www.autorita.energia.it/relaz_ann/relaz_annuale.htm

[57] Law 290/03 is available at: http://www.parlamento.it/parlam/leggi/03290l.htm.

[58] The *"Cassa Depositi e Presiti"* is a public company whose role is "[to]foster the development of public investment, local utility infrastructure works and major public works". Its main shareholder is the Ministry of Economics and Finance, which holds a 70% stake.

3.2.3. Distribution

Electricity distribution is carried out by private companies which have obtained a *concession* from the Ministry of Economic Development (the former Ministry of Industry). Distribution is carried out through high, medium and low voltage networks.[59] Legislative Decree number 79/99, which transposed into Italian Law the first EU Directive on the internal electricity market, established that:

- Each municipality should award one electricity distribution concession; and
- Each municipality should have only one electricity distributor.

As a consequence of these laws, the number of distributors has decreased continually since 2000. In 2006, the number of distribution networks operating in the market was 169.

3.2.4. Wholesale and Retail Markets

The electricity sales activity includes wholesale and retail sales.[60] According to latest Aeeg's annual report for the European Commission, which analysed the degree of competition in wholesale and retail markets in 2006,[61] there appears to be more competition in the wholesale market than in the retail market.

When considering the wholesale market, only four company groups appear to have a market share of 5% or more:[62]

1. Edison Group with a market share of 15.8%;
2. Enel Group, with its market share of 14.8%;
3. Eni Group, with a market share of 7.8%
4. Sorgenia Group, with a market share of 5.5%

The Authority undertook a survey in 2007 among the wholesalers and retailers in order to assess the degree of competition in electricity sales. A total of 264 companies answered the questionnaire, of which:

- 213 declared they were not vertically integrated with generators or distributors;
- 25 companies declared they were vertically integrated with generators;
- 6 companies declared they were vertically integrated with distributors; and
- 20 companies declared they were vertically integrated with generators and distributors.

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59 In case of distribution networks, the high voltage portion of the network is generally small.

60 Final customers are defined by the regulator as those customers purchasing electricity entirely for their own use; on the other hand, wholesale customers are defined as those customers purchasing electricity with the aim to re-sell it. See also paragraph 3.3,

61 Aeeg's Annual Report for the European Commission, published in July 2007, is available at the website: http://www.autorita.energia.it/pubblicazioni/annualreport07.pdf

62 The market share of the four major company groups represent about 44% of the whole market.

3.3. Status of Retail Competition

5. Are retail markets for electricity (and gas, if applicable) open to competition, for some customers or all (if some, which)?

6. How many retailers are in the market? Do they serve the whole retail market in this jurisdiction or just part of it (e.g. some customer groups, some areas only)?

7. What are the entry conditions of the retail market and other relevant markets?

The Legislative Decree 79/99 provided a broad definition of “customers” that included:[63]

§ *Distributors* (who, at that time, purchased electricity for sale to customers that were not eligible to freely choose their supplier);

§ *Final customers*, defined as customers purchasing electricity entirely for their own use;

§ *Wholesale customers* (“*clienti grossisti*”), defined as customers purchasing electricity in order to re-sell it inside or outside their own national system, without undertaking the activities of generating, transmitting or distributing the electricity in EU countries (i.e. wholesalers).

This segmentation is consistent with the definition of “customers” in European Directive 96/92/EC.[64] The definition of customers has been revised by the European Directive 2003/54/EC (which has replaced Directive 96/92/EC) and now includes only final customers and wholesale customers. [65]

Final customers were further segmented into:

§ Eligible customers (i.e. customers eligible to choose their supplier, mainly large customers); and

§ Non-eligible customers (i.e. customers not eligible to choose their supplier, mainly small customers)

The implementation of the European Directive 2003/54/EC opened up the market for customers segments in two phases:

§ from 1 July 2004 all non-household customers became eligible to freely choose their supplier;

§ from 1 July 2007 all customers are free to chose their supplier.

According to latest data on the number of electricity customers, which refer to 2006, there are about 35 million electricity customers, 27 million of which are residential customers.

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[63] See art. 2 “Definizioni” of Legislative Decree 79/99. The text of Legislative Decree 79/99 is available at the website: http://www.parlamento.it/leggi/deleghe/99079dl.htm..

[64] The European Directive 96/92/EC is available at the website: http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:31996L0092:EN:HTML

[65] The European Directive 2003/54/EC is available at the website: http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2003:176:0037:0055:EN:PDF.

Given the opening of the market to all customers, the Authority has highlighted the importance of promoting policies aimed at facilitating competition in the retail market.

Currently, energy supply to final customers is not regulated by the Authority; therefore there is no detailed information over the exact number of suppliers (retailers or wholesalers). Aeeg proposed that the companies should file a form providing their most important details and contacts. Given the information collected through this request, the Authority has published a list of electricity suppliers operating in the entire national territory, in both the wholesale and the retail markets. According to this list, there are around 470 companies operating in the retail and wholesale markets. Note however that this is not an official list and that operators are not obliged to file the form.

The Authority set out specific requirements in Decision 134/2007[66] that an operator selling electricity in the retail market must fulfil in order to be registered in the published list. The Authority also set out the legal character as well as the capital and financial requirements that a company has to achieve, in accordance with the Decree of the President of the Italian Republic no. 445/00.

3.4. Policy of Government/Regulatory Authorities

8. **What is the policy of the Government and/or the regulatory authority in relation to AMI?**
9. **Are there any laws/decrees or other provisions that concern AMI? Can you provide a brief summary of their content?**
10. **What is the nature or extent of regulatory intervention in AMI arrangements?**
11. **Have regulatory authorities mandated the deployment of AMI or left it to the market? Who is directly paying for AMI?**
12. **Have regulatory authorities enacted specific regulatory provisions to mandate, facilitate or incentivise the deployment of AMI?**
13. **Are there any regulatory or industry statements of technical requirements concerning AMI?**
14. **Where there has been a mandatory deployment, what has been the time frame and any other requirements for the deployment of AMI? What requirements were included in the laws or regulations used to mandate the AMI rollout?**
15. **How and over what time frame are the costs of AMI services being recouped (i.e. either a regulatory depreciation period or a commercial expectation)?**

3.4.1. Regulatory Goals and AMI Legislation

In Decision 292/06, as modified by Decision 235/07, Aeeg sets out the terms and conditions for deployment of the *Advanced Metering Infrastructure* (AMI) for low voltage customers. In doing so, Aeeg aims at achieving the following goals:

66 The Decision number 134/2007 is available at the website: http://www.autorita.energia.it/docs/07/134-07all.pdf.

- Guarantee competition in the retail market for all customers;
- Deploy AMI in order to offer all customers (including low voltage customers) the ability to take advantage of time-of-use tariffs.

3.4.2. Regulatory Policy Provision for Deployment of AMI

Decisions 292/06 and 235/07 provide that the installation of advanced electronic meters for all low voltage users is ***mandatory***. Distributors are responsible for deployment of AMI for all low voltage end-users.

The decision sets the technical requirements for meters and the timeframe for deployment of the AMI. End-users are not required to pay at the time the meter is physically installed at their premises, but the regulator allows, for the period of 2008-2011, recovery of installation costs through the metering tariff for non-domestic customers and through the overall tariff that covers transmission, distribution and metering costs for residential customers:

A. Technical Requirements: Decisions 292/06 and 235/07 set the minimal technical requirements for both the "mono-phase" meters and the "three-phase" meters provided to low voltage customers.[67] Both mono-phase and three-phase meters can be read and managed remotely.[68]

B. Timeframe: For mono-phase and three-phase meters, the Authority sets the timeframe required for their installation:

   – For all low voltage supply points where available capacity is 55 kW or less, the distributor has to install smart meters according to the following timetable:

      i) 25% of the total number of supply points by 31/12/2008;

      ii) 65% of the total number of supply points by 31/12/2009;

      iii) 90% of the total number of supply points by 31/12/2010;

      iv) 95% of the total number of supply points by 31/12/2011;

   – For all low voltage supply points where available capacity is more than 55 kW, the distributor will have to complete replacement of old meters by 31/12/2008.

By 30 June of the year following the one in which smart meters have been installed, companies responsible for reading and processing metering data have to make available the services of remote reading and data processing.

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[67] The difference between the mono-phase and the three-phase meters is that the three-phase allows also for metering of re-active power.

[68] Mono-phase and three-phase meters can further be designed in such a way as to allow for metering both injected and withdrawn electricity in dispatching points where both injection and withdrawal is allowed.

3.4.3. AMI Cost Recovery

The regulator allows for recovery of AMI costs through:

§ the metering tariff MIS (*"Tariffa per il servizio di misura"*) for non-domestic customers. The MIS tariff is differentiated by voltage level and includes two terms, a fixed term (MIS_1) and a variable term (MIS_3):

– MIS1 is expressed in euro cents per supply point per year;

– MIS3 is expressed in euro cents per kWh.

The tariff component MIS is designed to cover all the installation and maintaining costs related to metering, as well as costs incurred to read and record metering data;

§ the overall tariff that covers transmission, distribution and metering costs for residential customers. We understand that in the case of residential customers the metering component is a fixed term expressed in euro cents per supply point per year.

The regulator has set the useful life of smart meters for low voltage supply points equal to 15 years. However, art. 30.5 of Aeeg's Decision 348/07 appears to limit the cost that can be recovered by the distributor as it states that in the event that the average gross investment cost reported by the distributor for each supply point is more than 80% higher than the average national investment cost, the cost exceeding this threshold will not be included in the regulatory asset base.

3.5. Roles of Market Players

16. What are the roles and responsibilities of (1) distributors; (2) retailers or (3) intermediaries and the extent to which each has been primarily or solely responsible for AMI arrangements?

17. Who owns the meters and communication infrastructure?

18. Who installs the meters?

19. Who maintains the meters?

20. Who operates the communication infrastructure?

21. Who provides, accesses and processes data?

22. Who are the parties involved in these services and on what basis have the roles been allocated between the parties involved in AMI services?

23. If applicable, how is interoperability between different AMI services and between different operators/providers ensured?

The so-called *Testo Integrato*, published in December 2007 (Aeeg's Decision 348/07), regulates electricity transmission, distribution and metering. It is the reference document for instructions regarding the electricity metering activity. In particular, in this document the regulator sets out the responsibilities of and the obligations for interoperability between the different parties in deployment of AMI:[69]

1. The party responsible for the *installation* and *maintenance* of smart meters is:
    a) The distribution company in the case of the supply points;
    b) The generator in the case of injection points taking power from generating plants;
    c) The distributors at the interface between the distribution network and the national grid;
    d) The “upstream” distributor at the interface between two distribution networks, where the “upstream” distributor is the distributor managing the distribution network out of which electricity flows.
2. The party responsible for *collecting*, validating and *storing* metering data is:
    a) The distribution company in the case of the supply points;
    b) The transportation company or the distributor in the case of injection points;
    c) The distributors at the interface between the distribution network and the national grid;
    d) The “upstream” distributor at the interface between two distribution networks, where the “upstream” distributor is the distributor managing the distribution network out of which electricity flows.

The party in charge of collecting, validating and storing the metering data, as defined in the previous point 2, is also responsible for communicating the registered data to Terna, the Italian transmission system operator.

In the case of a “dispatching point”, where both injection and supply of electricity are allowed:

§ if such point allows for injection from a generating plant and the supply of electricity is needed for generation services, the dispatching point is considered to be an injection point and rules for injection points apply;[70]

§ in all other cases, the dispatching point is considered to be a supply point and rules for supply points apply.

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[69] The *Testo Integrato* is included in Annex A of the Decision 348/07. The updated version of Decision 348/07 is available at the website: http://www.autorita.energia.it/docs/07/348-08allanew.pdf

[70] In case of dispatching points serving generating plants where both injection and withdrawal are allowed and electricity withdrawal is needed for generation services, the generator is required to install a meter which allows for metering of both injected and withdrawn electricity.

3.6. Progress to Date

24. What has been the progress to date?

25. What is the extent of AMI penetration?

26. What proportion of customers and, in particular, of residential customers have received smart meters?

There are no comprehensive data on market penetration of smart meters. As distributors have a key role in installation of smart meters, a preliminary assessment of market penetration by smart meters can be derived from the meter replacement plans of the main distributors.

§ ENEL Distribution

Enel Distribution, as stated in Aeeg's annual report published in 2007, is the main distributor in Italy, with a market share in the household segment of about 80%. According to Enel's website, the substitution of old meters with smart meters is almost completed (30.7 million old meters replaced out of about 32 million old meters in total).[71]

Further, in 2007, the company carried out about 188 million remote readings of metering data and 8 million operations related to management of supply contracts. By the end of March 2008, the company carried out about 60 million remote readings of metering data and about 3 million operations related to management of supply contracts.

Enel has undertaken the replacement programme at a national level and, having already installed 31 million new electronic meters, the company is planning to conclude the replacement programme for the entire national territory by the end of 2008.

§ ACEA Distribution

Acea's replacement programme foresees the involvement of all customers in the area of Rome and Formello, amounting to approximately 1,500,000 customers in all. The distribution company is planning to conclude the replacement programme by the first half of 2009.

§ HERA

In its website, and in particular the website relating to the branch of the company serving the cities of Imola and Faenza, HERA states that it will start the meter replacement programme from April 2008. The first stage of the programme will include the installation of 300 new electronic meters in the area of Imola and Faenza that will be used to test the method of organization adopted by the company and to modify its installation strategy, if necessary.

After this pilot programme, the installation programme will continue and electronic meters will be gradually installed in all the areas served by HERA. The company intends to complete the process before 2011.

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[71] The information regarding Enel's smart meters project can be found at: http://www.enel.it/distribuzione/enel_distribuzione/la_nostra_rete/contatoreelett/progetto/progetto/

§ AGSM

AGSM started the electronic meter replacement programme in May 2007, by replacing 1,000 old meters with new electronic meters. The company is planning to replace a total of 170,000 meters, in the municipalities of Verona and Grezzana over a period of about two years.

4. Netherlands

4.1. Dutch Energy Market Background

4.1.1. Overview of Sector Structure

1. **Are energy businesses (generation, retail, networks) privately or state owned or controlled?**
2. **What is the extent of vertical integration in the market between (1) generation, wholesale trading and retailing (2) generation/wholesale and transmission networks and (3) retailing and distribution networks?**
3. **How many distribution networks are in the market?**
4. **How many retailers are in the market? Do they serve the whole retail market in this jurisdiction or just part of it (e.g. some customer groups, some areas only)?**

§ **Generation and Supply**

Since the Dutch energy sector became fully liberalised in 2004 it has consolidated around a small group of vertically integrated energy companies and a number of small companies active in either retail or distribution. Virtually all electric and gas distribution networks (referred to in the Netherlands as “network operators”) in the Netherlands are owned by Dutch municipalities, although the Dutch state owns Tennet, the national grid company.

The most noteworthy foreign participation in the Dutch electricity market comes from the private utilities E.ON and Electrabel, which acquired, two large vertically integrated utilities whose activities are now mostly limited to electricity generation and wholesale trading. In addition to these to firms, some smaller foreign entry exists, for instance through the 2005 acquisition of electricity retailer Oxxio by the British company Centrica.[72]

Almost all distribution networks also own retailing businesses. Retailing activities are dominated by three vertically integrated utilities Nuon, Essent, and Eneco, which together also hold around 80% of the retail market.[73] These three integrated utilities also hold around 40% of the total electricity generation capacity in the Netherlands, with the other 60% being divided among the two aforementioned foreign entrants (20% and 10%, respectively), and a large number of other players (30%).[74]

In total, there are around thirty electricity retailers and twenty gas retailers active in the Netherlands, excluding multiple licensees owned by the same company.[75] Most of these retailers are active in both electricity and gas retail markets, but around ten independent

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72 Source: http://www.centrica.co.uk

73 DTe, “Over transparantie en vertrouwen” - Marktmonitor, ontwikkeling van de Nederlandse kleinverbruikersmarkt voor Elektriciteit en Gas (Juli 2006 – Juni 2007), October 2007.

74 Source: NERA Economic Consulting based on industry sources.

75 http://www.dte.nl/nederlands/energiebedrijven/wie_is_wie_op_de_energiemarkt/de_leverancier_is_een_vergunninghouder.asp (“Who is who on the energy market”).

retailers focus exclusively on electricity. Most new entrants operate within a local area (e.g. a municipality) or focus on niche markets such as green energy.

§ Networks

The national high-voltage electricity transmission network, owned by the Dutch state through Tennet, is a fully unbundled transmission system operator (TSO).

There are currently ten licensed electricity distributor networks in the Netherlands,[76] and fifteen licensed gas distribution networks.[77]

4.1.2. Status of Retail Competition

5. Are retail markets for electricity (and gas, if applicable) open to competition, for some customers or all (if some, which)?

6. What are the entry conditions of the retail market and other relevant markets?

Since 1 July 2004, both electricity and gas retail markets have been fully open to competition for all types of customers.

New entrants must obtain a retail licence before they are allowed to participate in the market. The Dutch energy regulator, DTe, is responsible for awarding licences to applicants who have demonstrated they possess the organisation, as well as the sound financial and technical background, required to deliver a reliable service against reasonable tariffs and conditions.

In 2006, about 5% of customers switched their electricity supplier. In the period July 2006 to June 2007, the rate of switching by electricity consumers was slightly higher, at 7%.[78] (The retail gas market recorded similar figures.)

4.2. Policy of Government/Regulatory Authorities

4.2.1. Regulatory goals and AMI legislation

7. What is the policy of the Government and/or the regulatory authority in relation to AMI?

The situation in the Netherlands has changed recently. On 4 March 2008, the Minister of Economic Affairs submitted to Parliament a proposal for a new law that would require distribution networks to install AMI for all end users of electricity and gas in the Netherlands in six years from 2009.[79]

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76 http://www.dte.nl/nederlands/elektriciteit/transport/overzicht_netbeheerders/index.asp

77 http://www.dte.nl/nederlands/gas/transport/overzicht_netbeheerders/aanwijzing_netbeheerders.asp

78 DTe, "Over transparantie en vertrouwen" - Marktmonitor, ontwikkeling van de Nederlandse kleinverbruikersmarkt voor Elektriciteit en Gas (Juli 2006 – Juni 2007), October 2007, page 46-47.

79 http://www.ez.nl/Actueel/Pers_en_nieuwsberichten/Persberichten_2008/Maart_2008/Wetsvoorstel_verbetering_kleinverbruikersmarkt_elektriciteit_en_gas_naar_de_Tweede_Kamer

4.2.2. Regulatory Policy Provisions for Deployment of AMI

8. What is the nature or extent of regulatory intervention in AMI arrangements?

9. Have regulatory authorities mandated the deployment of AMI or left it to the market? Who is directly paying for AMI?

10. Have regulatory authorities enacted specific regulatory provisions to mandate, facilitate or incentivise the deployment of AMI?

11. Are there any laws/decrees or other provisions that concern AMI? Can you provide a brief summary of their content?

In first instance, the Dutch energy regulator, DTe, participates in the AMI arrangements by regulating the metering tariffs, which determine the rate at which distribution networks can recover the costs incurred in the roll-out of the new meters.

Secondly, the explanation[80] to the proposed law allows the Dutch competition authority, the NMa (which includes DTe, the office of the energy regulator), to provide distribution networks with additional incentives to complete the roll-out of AMI within the designated six-year period. The proposal leaves the NMa to decide what means would provide effective incentives.

If it is accepted by the Dutch Parliament, the proposed law prescribes deployment of AMI in the Netherlands over the next six years. The distribution networks would pay directly for AMI, which would be included in their regulatory asset base (RAB). Distribution networks recover investments in the RAB through regulated metering tariffs.

So far, there are no specific provisions to mandate, facilitate or incentivise the deployment of AMI, other than the standard metering charges. The Dutch Ministry of Economic Affairs is responsible for creating such a mandate in the form of the proposed law. However, the proposal leaves room for the regulator to provide additional incentives to distribution networks to ensure a timely completion of the roll-out (see question 8).

If it is accepted by the Dutch Parliament, the proposed law would prescribe deployment of AMI in the Netherlands in the next six years. The distribution networks would pay directly for AMI, which would be included in their regulatory asset base. Distribution networks recover their RAB investments through regulated tariffs, in this case the regulated tariff for metering services.

12. Are there any regulatory or industry statements of technical requirements concerning AMI?

The Dutch Minister of Economic Affairs proposes to standardise AMI so as to facilitate its use by all parties involved (distributors, supply firms, and the regulator). For this reason,

80 Tweede Kamer der Staten Generaal, Wijziging van de Electriceitswet 1998 en de Gaswet ter verbetering van de electriciteits- en gasmarkt – Memorie van Toelichting, page 17.

technical specifications of smart meters will be included in the relevant legislation. The explanation to the proposed law specifies that standard meters should have:[81]

- a metering function;
- a switch function that allows distribution network to turn the electricity supply on or off by remote control;
- a signalling function that allows the distribution network to read remotely the quality of electricity supply, e.g. to monitor network losses;
- a communication function (e.g. a modem) that allows the distribution network to collect metering data remotely; and
- a regulation function that allows additional appliances to be connected to the meter; for example, the connection of decentralised generation equipment that may or may not operate, depending on data indicated by the meter.

The proposal further indicates that the standard for AMI is to be evaluated every two to three years and will be adapted to the latest (software) developments.

13. Where there has been a mandatory deployment, what has been the time frame and any other requirements for the deployment of AMI? What requirements were included in the laws or regulations used to mandate the AMI rollout?

If and after the current proposal is accepted in Parliament, AMI is to be rolled out over six years from 2009. The only further requirements particular to the roll-out of the meters are the following:[82]

- distribution networks have to maintain a periodic roll-out plan to provide transparency on actual roll-outs;
- distribution networks have to carry out priority requests by customers so long as these do not interfere with the six-year roll-out period; and
- customers have the option to have a third party install the new meter if the distribution network is unable to carry out a priority request.

4.2.3. AMI Cost Recovery

14. How and over what time frame are the costs of AMI services being recouped (i.e. either a regulatory depreciation period or a commercial expectation)?

The exact time frame over which distribution networks can recoup their investment is not yet known. The proposal specifies that smart meters are to be included in “the regulatory domain

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81 Tweede Kamer der Staten Generaal, Wijziging van de Electriceitswet 1998 en de Gaswet ter verbetering van de electriciteits- en gasmarkt – Memorie van Toelichting, page 14/15.

82 Tweede Kamer der Staten Generaal, Wijziging van de Electriceitswet 1998 en de Gaswet ter verbetering van de electriciteits- en gasmarkt – Memorie van Toelichting, page 15/16.

of distribution networks' physical infrastructure,'[83] which means meters become part of the regulatory asset base (RAB) and would be subject to a regulatory depreciation period. The Regulatory Accounting Rules currently assign an asset life of 30 years to meters "required for operational purposes", but do not discuss meters used for billing purposes.[84]

4.3. Roles of Market Players[85]

15. What are the roles and responsibilities of (1) distributors; (2) retailers or (3) intermediaries and the extent to which each has been primarily or solely responsible for AMI arrangements?

See question 11.

16. Who owns the meters and communication infrastructure?

The distribution networks.

17. Who installs the meters?

The distribution networks are in principle responsible for installation of the meters, but may hire a specialised metering equipment company to do so.

18. Who maintains the meters?

The Distribution networks are responsible for meter maintenance.

19. Who operates the communication infrastructure?

The explanatory memorandum to the proposed law identifies a communications modem as part of the meter installation (which is the responsibility of the distribution network). It is not explicit on the operation of communications infrastructure, but it does say that the metering tariff (to be paid to distribution networks) contains an element to cover the costs of 'making available the raw metering data' and that the distribution network is responsible for authorising third parties (retailers, or metering companies which retailers may hire to obtain and verify data) to access the metering data.[86] These obligations appear to make it inevitable that the distribution networks will have to operate a communications infrastructure.

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[83] Tweede Kamer der Staten Generaal, Wijziging van de Electriceitswet 1998 en de Gaswet ter verbetering van de electriciteits- en gasmarkt – Memorie van Toelichting, page 16.

[84] DTe, Regulatorische Accountingregels 2006, voor Regionale Netbeheerders Elektriciteit, Den Haag, March 2007.

[85] Answers in this section are taken from: Tweede Kamer der Staten Generaal, Wijziging van de Electriceitswet 1998 en de Gaswet ter verbetering van de electriciteits- en gasmarkt – Memorie van Toelichting, pages 11, 13.

[86] Tweede Kamer der Staten Generaal, Wijziging van de Electriceitswet 1998 en de Gaswet ter verbetering van de electriciteits- en gasmarkt – Memorie van Toelichting, page 21-22.

20. Who provides, accesses and processes data?

The retail companies collect and process information, and send it to both their consumers and the relevant distribution network.

21. Who are the parties involved in these services and on what basis have the roles been allocated between the parties involved in AMI services?

The services are divided between distribution networks and retail companies as described in questions 16-20. The roles have been assigned to separate activities related to physical installation and maintenance of the meters (distribution networks) from activities related to the administrative processing of the data for the customers (retail company).

22. If applicable, how is interoperability between different AMI services and between different operators/providers ensured?

The proposed law would standardise the functional capabilities of the advanced metering equipment (see question 12).

4.4. Progress to Date

23. What has been the progress to date?

At the moment, only a single retail company (Oxxio[87]) offers its customers the option of installing smart meters in the Netherlands. If the current proposal is approved in Parliament, all customers will have AMI installed by 2015.

24. When and where were policies set out? When did the implementation of the policy begin, if at all?

The Dutch Minister of Economic Affairs submitted her proposal to Dutch parliament on 4 March 2008. (See answers to questions #10 and #11.)

25. What is the extent of AMI penetration?

See question 23. It is unknown how many customers actually have smart meters installed at the moment, since they are currently being offered only by one independent retailer as a purely commercial venture.

26. What proportion of customers and, in particular, of residential customers have received smart meters?

See question 23. It is unknown how many customers actually have smart meters installed at the moment, since they are currently being offered only by one independent retailer as a purely commercial venture.

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87 Owned by Centrica.

5. Sweden

5.1. Swedish Energy Market Background

5.1.1. Overview of Sector Structure

1. **Are energy businesses (generation, retail, networks) privately or state owned or controlled?**
2. **What is the extent of vertical integration in the market between (1) generation, wholesale trading and retailing (2) generation/wholesale and transmission networks and (3) retailing and distribution networks?**
3. **How many distribution networks are in the market?**
4. **How many retailers are in the market? Do they serve the whole retail market in this jurisdiction or just part of it (e.g. some customer groups, some areas only)?**

Ownership of utilities in Sweden is mixed public/private and there is a large amount of vertical integration of the supply chain.

In the electricity market, the largest vertically integrated utilities are Vattenfall, Fortum and Sydkraft, which accounted for 87% of total electricity generation in Sweden in 2006.[88] They are owned by a mix of the Swedish Government and other private or public owners. For example, Vattenfall is 100% state-owned,[89] Fortum is a publicly traded company in which the Finnish state currently holds 50.8% of the shares,[90] and the shares of Sydkraft are split between the privately owned[91] German utility E.ON, which holds the majority, and Statkraft, the Norwegian state-owned generator company, which owns 44.6%.[92]

In 2004, the major utilities supplied roughly 50% of the retail electricity supply market, in which around 100[93] utilities operate in total. The major utilities own most of the regional transmission networks, which connect the national transmission network (owned by the Swedish state through Svenska Kraftnät) with the local distribution networks and larger electricity users. The major utilities also own a number of the local networks, with the remainder being owned by around 170[94] local municipalities.[95]

88 http://www.iern.net/country_factsheets/market-sweden.htm

89 http://www.vattenfall.com/www/vf_com/vf_com/369431inves/833939inves/index.jsp

90 Fortum, Interim Report 1-3/08, 24/04/2008, Page 14.

91 75.2% of E,ON's shares are owned by institutional investors, see: http://www.eon.com/en/investoren/965.jsp

92 http://annualreport2004.statkraft.gosu.no/docs/3/111/document128.ehtml

93 Energy Market Inspectorate (2005), The Swedish Energy Market – Theme: The Storm Gudrun, 2005, p27.

94 http://www.iern.net/country_factsheets/market-sweden.htm

95 Energy Market Inspectorate (2005), The Swedish Energy Market – Theme: The Storm Gudrun, 2005, p21, 27.

The Swedish natural gas market has a small number of companies and a high degree of vertical integration. Sweden does not have any indigenous sources of any natural gas, so all gas consumption must be met by gas imported through a pipeline with Denmark. The Danish utility Dong is responsible for half of all gas imports into Sweden, whilst E.ON Sverige imports the other half.[96] In addition to Dong, there are six other gas retailers, one of which (Sydkraft Gas) is also active in gas wholesaling. See Table 5.1. All of the gas companies own distribution networks.[97]

Table 5.1:
Swedish Gas Retail Market Shares

Company	Volume (GWh)	Market share (%)
Sydkraft Gas	4918	49%
Göteborg Energi	1697	17%
Nova Naturgas	1221	12%
Öresundskraft	897	9%
Lunds Energi	750	7%
Dong Sweden	275	3%
Ängelholms Energi	267	3%
Varberg Energi	72	1%
Total sales	10097	100%

5.1.2. Status of Retail Competition

5. Are retail markets for electricity (and gas, if applicable) open to competition, for some customers or all (if some, which)?

The Swedish electricity market was gradually liberalised over the period 1996 to 1999 and had been fully opened to competition by 1 November 1999.[98] Similarly, the Swedish gas market was opened up to competition gradually and was fully liberalised between 1 July 2005 and 1 July 2007.[99]

6. What are the entry conditions of the retail market and other relevant markets?

By 2006, around 30% of all electricity customers (both industrial and domestic) had switched suppliers since the electricity market began to be liberalised.[100] By 2007, the total percentage

96 Energy Market Inspectorate (2007), "The Swedish Energy market Inspectorate's report in accordance with the EC Directives for the internal markets for electricity and gas 2007", 2007, page 8.

97 Energy Market Inspectorate (2005), pages 38-39.

98 Ofgem, Domestic Metering Innovation, 1 February 2006, page 41.

99 http://www.iern.net/country_factsheets/market-sweden.htm

100 Energy Market Inspectorate (2006), "The Swedish Energy market Inspectorate's report to the European Commission", 2006, page 28. and Energy Market Inspectorate (2007), pages 45-46.

of domestic customers that had switched since liberalisation amounted to 55%.[101] The regulatory authorities do not report an exact percentage of industrial users that have switched since liberalisation.

Since liberalisation, the number of electricity suppliers in Sweden has dropped from 220 to around 150 by 2004, around a 100 of which actively sell electricity to end users. Between 1996 and 2004, foreign ownership of electricity suppliers in Sweden increased from 10% to 40%.[102]

There is currently no information available on customer switching in the Swedish market for natural gas. The regulator notes that "a large number of major industrial customers have changed their gas suppliers since 1 July 2005.[103] However, there are only 55,000 gas customers in Sweden, of which 2600 are classed as "corporate" and the rest as "domestic".[104]

5.2. Policy of Government/Regulatory Authorities

5.2.1. Regulatory Goals and AMI Legislation

7. **What is the policy of the government and/or the regulatory authority in relation to AMI?**
8. **Are there any laws/decrees or other provisions that concern AMI? Can you provide a brief summary of their content?**
9. **What is the nature or extent of regulatory intervention in AMI arrangement**

Until 2003, the law required distribution networks to read all customers' meters on an annual basis. Since then, a number of bills and ordinances have been passed that set different electricity metering requirements for different customer groups and focus on the frequency of meter readings rather than the (mandatory) introduction of AMI.

Hourly meter readings are required for all consumers with a connection larger than 63 Amp. The threshold was lowered in a 2005 ordinance, from 200 Amp to 63 Amp, with effect from 1 July 2006.[105] This change was done as part of the transposition of the EU Directive 2003/54/EC.[106] The motivation given in a regulator's report was: "This will have the effect of allowing a greater number of customers to be offered differentiated electricity prices and

[101] Energy Market Inspectorate (2007), page 7.

[102] Energy Market Inspectorate (2005), page 27.

[103] Energy Market Inspectorate (2007), pages 45-46.

[104] Energy Market Inspectorate (2007), pages 45.

[105] Defining the limit by reference to Amps is slightly unorthodox. At 220V or 400V, 63 Amps converts to 14 kW or 25 kW respectively. At 10kV, it corresponds to 630 kW.

[106] EC Directive 2003/54/EC concerning common rules for the internal market in electricity and repealing Directive 96/92/EC.

network charges, thus creating the necessary conditions for pricing that provide an incentive for using electricity more efficiently."[107]

Monthly meter readings are required for consumers with a connection below the 63 Amp threshold. This requirement was proposed by Government in a 2003 Bill[108] introduced through a 2005 Ordinance.[109] The main motivation was "provide customers with a stronger link between consumption and billing, which can promote energy efficiency and increased switching between suppliers".[110]

The legislation imposes no requirement that billing should be carried out using the monthly meter readings. Nor are there any requirements as to how the meters are to be read. However, in practice the requirement amounts to mandatory automatic meter reading.

5.2.2. Regulatory Policy Provisions for Deployment of AMI

10. Have regulatory authorities mandated the deployment of AMI or left it to the market? Who is directly paying for AMI?

11. Have regulatory authorities enacted specific regulatory provisions to mandate, facilitate or incentivise the deployment of AMI?

12. Are there any regulatory or industry statements of technical requirements concerning AMI?

The regulatory requirements are limited to the frequency of reading, i.e. (1) hourly readings for all connections > 63 Amp, (2) monthly readings for all other connections.

The use of AMI is in itself not mandated. The 2005 Ordinance merely lays down the requirement for distribution networks to provide monthly and hourly readings, and restates the existing requirement to read the meter when customers switch.[111] However, the metering frequency requirements effectively leave distribution networks with no choice but to make use of AMI. Distribution networks pay any costs incurred in fulfilling the metering

[107] Energy Market Inspectorate (2005), page 13: "Det främsta syftet var att ge kunderna en starkare koppling mellan förbrukning och fakturering samt förbättrad information om elförbrukningen, vilket kan främja energibesparingsåtgärder och rörligheten på elmarknaden."

[108] Bill 2002/03:85, http://www.regeringen.se/content/1/c4/20/25/30256a10.PDF

[109] The relevant Swedish regulation is 2006:1590, amending article 16 of ordinance 1999:716. See page 7 of Swedish language report of the Electricity Markets Inspectorate (undated), "Månadsvis avläsning och installation av fjärravlästa elmätare", at: http://www.energimarknadsinspektionen.se/upload/Rapporter/Fj%C3%A4rravl%C3%A4sta%20elm%C3%A4tare.pdf

[110] See page 7 of Swedish language report of the Electricity Markets Inspectorate (undated), "Månadsvis avläsning och installation av fjärravlästa elmätare".

[111] Förordning (1999:716) om mätning, beräkning och rapportering av överförd el ("Ordinance concerning the measurement, calculation and reporting of electricity"), http://www.riksdagen.se/webbnav/index.aspx?nid=3911&bet=1999:716 and Ellagen ("the electricity law") http://www.riksdagen.se/webbnav/index.aspx?nid=3911&bet=1997:857

frequency requirements. These costs will be recouped similarly to other distribution network costs through network charges.[112]

The relevant regulatory documentation does not mention any technical specifications for any AMI. However, the distribution networks are required to report meter readings to the system operator, supply companies, and other parties in a specific format with the acronym EDIEL.[113]

However, many companies are installing meters with more capabilities than required for monthly readings, including hourly meter readings, on-demand remote readings (requiring two-way communication), and in some cases load management. Several companies have indicated that they intend to use these features from 2009, thus going beyond the regulatory requirement.[114]

In a survey conducted in 2006, companies indicated that they are installing this additional functionality because cost for doing so are reasonably small and because they believe it will be useful to them in meeting possible future regulatory requirements, for load management purposes, and to save the cost of manual meter reading.[115]

13. Where there has been a mandatory deployment, what has been the time frame and any other requirements for the deployment of AMI? What requirements were included in the laws or regulations used to mandate the AMI rollout?

Please refer to questions 7, 9 and 11. The requirement for monthly meter readings takes effect on 1 July 2009. This was introduced by the following legislation:

- the 2003 Bill announcing the intention to change metering requirements; and
- the 2005 Ordinance formally introducing the requirements proposed in the 2003 Bill.

The requirement for hourly meter readings, which had also been proposed in the 2003 Bill, was introduced through a different 2005 Ordinance and took effect on 1 July 2006.

5.2.3. AMI Cost Recovery

14. How and over what time frame are the costs of AMI services being recouped (i.e. either a regulatory depreciation period or a commercial expectation)?

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112 http://www.energimarknadsinspektionen.se/upload/Tillsyn/N%C3%A4tnyttomodellen/Till%C3%A4mpning%20o%20 juridik/Beslut%20ursprungliga%20parametrar%20samt%20parametrar%20tariff%C3%A5ret%202003.pdf pp15-16

113 http://www.energymarketsinspectorate.se/upload/F%C3%B6reskrifter/54541_01-24_Stemfs%205.pdf

114 http://www.energimarknadsinspektionen.se/upload/Rapporter/Fj%C3%A4rravl%C3%A4sta%20elm%C3%A4tare.pdf, table of survey responses on p. 42

115 Andrea Badano, AMR för mindre elnätbolag – investeringsfaktorer, page 3.

Distribution networks have the legal obligation to meter electricity and to report the results to market participants, including supply companies.[116] The relevant documentation does not set a specific time frame for cost recovery. The regulator's analysis of costs and benefits uses a cost of capital of 6% and a 15 year depreciation period for equipment, noting that these parameters may differ for different companies.[117]

In recent years, regulation of distribution network revenues in Sweden has applied the costs of a model of a reference network, which uses a period of 18 years that seems to contradict the absence of such a time frame in the bill on metering.[118] Among the charges included in this model are costs of administration of the network. From 2004, these costs include the cost of installing the new meters.[119]

5.3. Roles of Market Players

15. What are the roles and responsibilities of (1) distributors; (2) retailers or (3) intermediaries and the extent to which each has been primarily or solely responsible for AMI arrangements?

16. Who owns the meters and communication infrastructure?

17. Who installs the meters?

18. Who maintains the meters?

The distribution networks are solely responsible for AMI arrangements.[120]

The distribution networks own the metering equipment through their obligation to meter electricity and report the results to other market participants.[121] The distribution networks also install and maintain the meters, using outsourcing where appropriate.[122]

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116 Förordning (1999:716) om mätning, beräkning och rapportering av överförd el ("Ordinance concerning the measurement, calculation and reporting of electricity"), http://www.riksdagen.se/webbnav/index.aspx?nid=3911&bet=1999:716 and Ellagen ("the electricity law") http://www.riksdagen.se/webbnav/index.aspx?nid=3911&bet=1997:857

117 Electricity Markets Inspectorate (2002), "Månadsvis avläsning av elmätare: Slutredovisning av regeringsuppdrag", 27 May 2002, page 20, note to table 1, available at: http://www.energimarknadsinspektionen.se/upload/Rapporter/El/Månadsvis%20avläsning%20av%20elmätare.pdf

118 http://www.energimarknadsinspektionen.se/upload/Tillsyn/N%C3%A4tnyttomodellen/Till%C3%A4mpning%20o%20juridik/Beslut%20ursprungliga%20parametrar%20samt%20parametrar%20tariff%C3%A5ret%202003.pdf, page 16.

119 http://www.energimarknadsinspektionen.se/upload/Tillsyn/N%C3%A4tnyttomodellen/Till%C3%A4mpning%20o%20juridik/Beslut%20ursprungliga%20parametrar%20samt%20parametrar%20tariff%C3%A5ret%202003.pdf, page 16 and http://www.energimarknadsinspektionen.se/upload/Tillsyn/Nätnyttomodellen/Hur%20Nätnyttomodellen%20fungerar.pdf, pages 1-2.

120 Energy Market Inspectorate, The Swedish Energy market Inspectorate's report in accordance with the EC Directives for the internal markets for electricity and gas 2007, 2007, page 9.

121 http://www.elradgivningsbyran.se/artikel/document/N%C3%A4tavtal%20och%20tariffer.%20Faktablad%20Stem.pdf

122 http://www.energimarknadsinspektionen.se/upload/Rapporter/Fjärravlästa%20elmätare.pdf

19. Who operates the communication infrastructure?

20. Who provides, accesses and processes data?

21. Who are the parties involved in these services and on what basis have the roles been allocated between the parties involved in AMI services?

22. If applicable, how is interoperability between different AMI services and between different operators/providers ensured?

The distribution networks operate the communications infrastructure, which mostly appears to make use of the mobile phone network. They have the legal obligation to meter electricity and report the results to market participants, including supply companies.[123] There is no need for interoperability of systems, or to interact with other parties, except in the provision of metering data (see answer to question 13 above).

5.4. Progress to Date

23. What has been the progress to date?

24. When and where were policies set out? When did the implementation of the policy begin, if at all?

24. What is the extent of AMI penetration?

26. What proportion of customers and, in particular, of residential customers have received smart meters?

The Electricity Market Inspectorate (Energimarknadsinspektionen – the regulator charged with overseeing and enforcing the rules) reported recently on progress.[124] A survey of distribution networks representing 3.6 million out of the total 5.2 million metering points indicated that 26% of meters had been replaced by 1 July 2007. This was slower than previously announced by distribution networks. Some proportion of installed meters does not yet have working communication links, and it is not clear that all companies have IT systems installed to handle the information received. However, the Energy Market Inspectorate indicates it does not think there is a need for further action to ensure compliance by 1 July 2009.

Projections compiled by the distribution networks included in the survey indicated that 78% of the required meters will be installed by 1 July 2008, and 94% by 1 July 2009.

Please refer also to the answers to questions 13 and 23.

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123 Förordning (1999:716) om mätning, beräkning och rapportering av överförd el (“Ordinance concerning the measurement, calculation and reporting of electricity”), http://www.riksdagen.se/webbnav/index.aspx?nid=3911&bet=1999:716 and Ellagen (“the electricity law”) http://www.riksdagen.se/webbnav/index.aspx?nid=3911&bet=1997:857

124 Electricity Market Inspectorate (undated), pages 9-10.

6. California

6.1. California Energy Market Background

6.1.1. Overview of Sector Structure

1. **Are energy businesses (generation, retail, networks) privately or state owned or controlled?**
2. **What is the extent of vertical integration in the market between (1) generation, wholesale trading and retailing (2) generation/wholesale and transmission networks and (3) retailing and distribution networks?**
3. **How many distribution networks are in the market?**
4. **How many retailers are in the market? Do they serve the whole retail market in this jurisdiction or just part of it (e.g. some customer groups, some areas only)?**

The bulk of Californian electricity load is covered by the CAISO (California Independent System Operator). CAISO operates a real-time wholesale market and operates the portion of the grid owned by three major investor-owned utilities (IOUs)—Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E).[125] These utilities own the bulk of the distribution networks and about 80% of the total transmission capacity in California. Their service territories collectively represent about 68% of the state's load. Following the passage in 1996 of California's electricity restructuring law, AB 1890,[126] the three IOUs divested the majority of their generation capacity, including gas-fired units, although they retained some of the nuclear and hydro plants.

In addition to the IOUs, about 12 competitive energy retailers, known as Energy Service Providers (ESP), supply electricity within the CAISO's control area.

Besides the CAISO control area, there are four smaller control areas in California, each of them operated by a publicly-owned, vertically-integrated, utility— (1) Los Angeles Department of Water and Power (LADWP), (2) Sacramento Municipal Utility District (SMUD), (3) Imperial Irrigation District, and (4) Turlock. These utilities are not subject to the jurisdiction of the California Public Utilities Commission (CPUC); rather, they are operated as a department of the City Government and regulated by elected Boards of Directors.

In total, about 47 utilities supply electricity in California. Besides the three IOUs, a total of 27 municipal utilities deliver 24% of California load. The remainder of the California load is supplied by the following organisations:

- four rural electric cooperatives that are regulated by a Board of Directors;
- four Irrigation Districts, which are political subdivisions of the state and regulated by Boards of Directors elected by the public;

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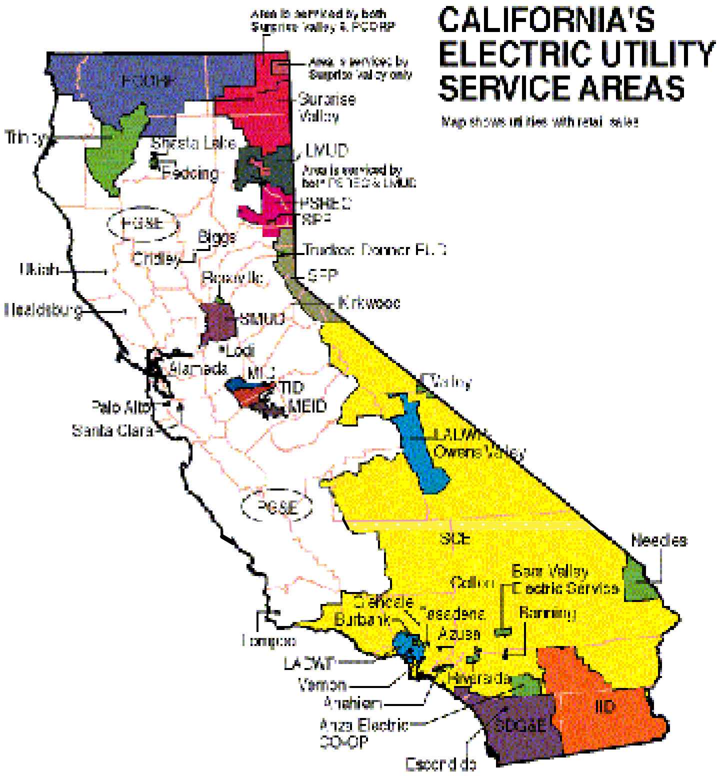
125 The Investor Owned Utilities (IOUs) in California handed over their dispatch control to the CAISO on 31 March 1998.

126 Assembly Bill 1890 was signed into law on 23 September 1996 as Chapter 854 of the Statutes of 1996.

- § two Public Utility Districts (PUD) owned by customers and regulated by a Board of Directors elected by registered voters,
- § two Federal projects regulated by FERC, and
- § two Public Power Agencies (PPA) that are owned, operated and regulated by a county.

Finally, parts of California are included within three multi-state control areas, which are independently operated by three vertically-integrated IOUs—PacifiCorp, Sierra Pacific, and Nevada Power.

Figure 1. California's Electric Utility Service Areas



6.1.2. Status of Retail Competition

5. Are retail markets for electricity (and gas, if applicable) open to competition, for some customers or all (if some, which)?

Retail competition, known in California as Direct Access (DA), began in 1999 and was only available to customers located in the IOUs' service territories. DA was suspended by the CPUC in September 2001 as a result of the 2000/2001 energy crisis in California.[127] Customers who had entered into electricity supply contracts with competitive retailers

[127] Public Utilities Commission of the State of California, Decision D.01-09-060 on 20 September 2001.

(known as "Energy Service Providers", or ESP) prior to 20 September 2001 were permitted to keep those deals in force until expiration of the contract term. The execution of any new DA contracts was prohibited. At the moment, only a few large industrials, representing less than 10% of total statewide consumption, remain under contract with competitive retailers.[128]

6. What are the entry conditions of the retail market and other relevant markets?

At the moment there is no active competitive retail market in California, due to the prohibition on new contracts with competing retailers.

6.2. Policy of Government/Regulatory Authorities

6.2.1. Regulatory goals and AMI legislation

7. What is the policy of the Government and/or the regulatory authority in relation to AMI?

The California Public Utilities Commission (CPUC) and the California Energy Commission (CEC)[129] have focused on energy conservation measures ever since the energy crisis took place in California in the summer of 2000 and first half of 2001. The 2002 CPUC proceeding R.02-06-001 made clear that meeting California energy growth needs – both natural gas and electricity – while optimizing energy conservation would be a primary long-term goals of its energy policy.

In May 2003, the CPUC, the CEC and the California Power Authority (CPA)[130] jointly developed the first Energy Action Plan (EAP) for California. The EAP articulated various action items aimed at avoiding excessive price spikes in electricity and natural gas, as well as improving the reliability of the infrastructures needed to provide those services.[131] Soon after, in June 2003, CPUC Decision 03-06-032 (formulated under the R. 02-06-001 framework) approved specific dynamic demand response (DR) programs for the utilities' large electricity customers and set long-term energy reduction goals for each IOU, in order to achieve a 5% (approximately 2,500 to 2,750 MW) reduction in statewide peak demand by 2007.

In February 2004, under the same proceeding, the CPUC directed the three IOUs to file applications for deployment of Advanced Metering Infrastructure (AMI) for electricity and gas customers. The AMI systems would provide interval meters and associated communication infrastructure to enable participation in dynamic tariffs, provide customers with access to hourly usage data, and promote utility operating efficiency through automated meter reading, improved detection of outages and remote restoration of service. The utilities'

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[128] In 2007, the CPUC opened an investigation as to how and when the DA retail market should be reopened in California. In February 2008, the CPUC established that it will not be able to reinstitute DA, as long as the CA Department of Water Resources (DWR) continues procuring power for the utilities under long-term contracts signed during the energy crisis.

[129] The CEC responsibilities include forecasting future energy needs, promoting energy efficiency through appliance and building standards, and supporting renewable energy technologies.

[130] CPA is a state authority that provides financing for the construction of new generation projects to meet the state's energy needs and to maintain reserves.

[131] Energy Action Plan, California Public Utilities Commission, 8 May 2003.

AMI deployment applications were to be accompanied by a cost-benefit analysis and a proposed deployment timeframe.[132]

6.2.2. Regulatory Policy Provisions for Deployment of AMI

8. What is the nature or extent of regulatory intervention in AMI arrangements?

9. Have regulatory authorities mandated the deployment of AMI or left it to the market? Who is directly paying for AMI?

10. Have regulatory authorities enacted specific regulatory provisions to mandate, facilitate or incentivise the deployment of AMI?

11. Are there any laws/decrees or other provisions that concern AMI? Can you provide a brief summary of their content?

As mentioned above, regulatory policies concerning price-response enabling technology begun in 2002, when the CPUC asked IOUs to start exploring demand response programs.

On 6 June 2002, under R.02-06-001, the CPUC asked the three IOUs to assess voluntary programs that would enable utilities to offer DR options to customers in order to reduce peak consumption and enhance electric service reliability. In particular, the three California IOUs were directed to conduct a two-year statewide pilot (the SmartMeter™ program) to gauge customer interest in dynamic pricing options.[133] The pilot showed that customers were interested in enrolling in such pricing options, which would allow utilities to achieve substantial savings in power procurement.

While the CPUC's initial emphasis on smart meters was to promote dynamic pricing options and demand response programs for electricity, the CPUC recognised that natural gas customers could also benefit from AMI infrastructure and should receive smart meters to the extent that they were cost-effective. In February 2004 the CPUC specifically mandated IOUs to perform a broad investigation into AMI deployment and to file full-scale AMI deployment applications for both electricity and natural gas customers (where both types of services were provided). The utilities' applications to deploy AMI were to be accompanied by a cost-benefit analysis and a proposed timeframe for deployment. [134] The CPUC established that the IOUs would be responsible for incurring the costs associated with AMI deployment in the first instance. As part of this analysis, the utilities were asked to assess the maximum amount of demand response that could be achieved cost-effectively and were directed to submit their business case analyses from 15 October (but no later than 15 December) of 2004. The CPUC

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132 Joint Assigned Commissioner and Administrative Law Judge's Ruling Providing Guidance For The Advanced Metering Infrastructure Business Case Analysis, Rulemaking 02-06-001, Public Utilities Commission of the State of California, 19 February 2004.

133 Assigned Commissioner and Administrative Law Judge's Ruling on the Budget for the Statewide Pricing Pilot, Advanced Demand Response System, and Information Display Pilot, Public Utilities Commission of the State of California, 6 June 2002.

134 Joint Assigned Commissioner and Administrative Law Judge's Ruling Providing Guidance For The Advanced Metering Infrastructure Business Case Analysis, Rulemaking 02-06-001, Public Utilities Commission of the State of California, 19 February 2004.

established that the costs associated with AMI deployment would be borne in the first instance by the IOUs.

On 21 July 2004, the CPUC established the specific business case analysis framework for AMI that IOUs should follow.[135] Under this framework, the AMI analysis should:

§ Identify the costs and benefits of implementing an AMI rollout (both partial and full deployment); and

§ Include scenarios with and without the benefit of demand response tariffs in place, as well as a 'business as usual' scenario (no AMI rollout).

The CPUC provided broad guidelines for the AMI case analysis, as follows:

§ The analysis period would cover 2006 to 2021.

§ Benefits and costs would be calculated relative to a Base Case.

§ Costs and benefits would be presented as 2004 present value dollars, with annualized nominal values in work papers.

§ An extensive literature search would be performed in order to identify data or methods used by other electric or gas utilities to estimate benefits associated with AMI. The utility could use a combination of methods for gathering benefits and cost information (e.g., Requests for Proposals for AMI technology acquisition; benchmarks from other utilities; in-house cost analysis and actual in-house costs; estimation of utility operational benefits of AMI deployment under different rollout scenarios).

§ The utility could propose a specific method to compute the avoided capacity and energy costs achieved with AMI and DR programs.

§ Any potential costs and benefits that could not be easily quantified or for which no dollar value could be derived due to uncertainty or lack of data would be reflected in the analysis and the utility would include a qualitative assessment of that value.

§ The discount rate would be the utility's cost of capital.

§ The total DR savings estimates would be based on a weighted average of savings under average and hot weather conditions, and would be developed using Monte Carlo or other simulation techniques.

12. Are there any regulatory or industry statements of technical requirements concerning AMI?

The CPUC established, in its February 2004 ruling, that the AMI system should be able to provide the necessary metering and communications capability to support economically a wide variety of rate and associated customer service options. The Commission did not specify

[135] Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, Application 05-03-015, Public Utilities Commission of the State of California, 15 March 2005, pp. 4-5.

AMI technical requirements, but did rule that AMI should be sufficient to meet, at a minimum, the following six functionality requirements:[136]

(1) Implementation of the price responsive tariffs for all customers:

- § Residential and Small Commercial Customers (<200 kW), on an opt-out basis:
  - (a) Time-of-Use (TOU) rates with ability to change TOU period length;
  - (b) Critical Peak Pricing with fixed (day ahead) notification (CPP- F);
  - (c) Critical Peak Pricing with variable or hourly notification (CPP-V) rates;
  - (d) Flat/inverted tier rates.
- § Large Customers (between 200 kW and 1 MW), on an opt-out basis:
  - (a) Time-of-Use;
  - (b) Critical Peak Pricing with fixed or variable notification;
  - (c) Two part hourly Real-Time Pricing.
- § Very large customers (> 1 MW), on an opt-out basis:
  - (a) Time-of-Use Pricing;
  - (b) Critical Peak Pricing with fixed or variable notification;
  - (c) Two part hourly Real-Time Pricing.

(2) Collection of usage data (interval data) at a level of detail that supports customer understanding of hourly usage patterns and how those usage patterns relate to energy costs.

(3) Customer access to personal energy usage data with sufficient flexibility to ensure that changes in customer preference of access frequency do not result in additional AMI system hardware costs.

(4) Compatible with applications that utilize collected data to provide customer education and energy management information, customized billing, and support improved complaint resolution.

(5) Compatible with utility system applications that promote and enhance system operating efficiency and improve service reliability, such as remote meter reading, outage management, reduction of theft and diversion, improved forecasting, workforce management, etc.

(6) Capable of interfacing with load control communication technology.

The Commission noted that utilities and other parties might need to specify additional levels of system functionality or technical requirements in order to ensure accurate cost

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136 Joint Assigned Commissioner and Administrative Law Judge's Ruling Providing Guidance For The Advanced Metering Infrastructure Business Case Analysis, Rulemaking 02-06-001, Public Utilities Commission of the State of California, 19 February 2004.

comparisons between different AMI systems.[137] The CPUC ordered a multi-agency working group[138] to develop a matrix of any additional specifications needed to implement the CPUC policy direction above.[139]

13. Where there has been a mandatory deployment, what have been the time frame and any other requirements for the deployment of AMI? What requirements were included in the laws or regulations used to mandate the AMI rollout?

The Commission directed each IOU to complete a business case analysis and file an AMI deployment strategy before the end of 2004. The CPUC did not mandate a specific timeframe to begin implementing the full-scale AMI. Rather, IOUs were asked to propose AMI rollout timetables based on their specific deployment strategy.

On 15 October 2004, PG&E filed a preliminary AMI business case analysis in compliance with the CPUC's ruling of 21 July 2004. SDG&E and SCE also filed preliminary analyses on 22 October 2004. Although all three utilities had completed much of the analysis that was required, the CPUC established that none of them fully complied with CPUC directives in the 21 July 2004 ruling. As a result, the CPUC directed the three IOUs to submit a revised (final) AMI deployment strategy no later than 15 March 2005.[140]

The CPUC allowed the IOUs to postpone their final AMI schedules provided they argued "legitimate reasons". SCE and SDG&E initially found AMI not cost-effective and as a result they were granted an extension in their filing of AMI deployment applications. PG&E received the Commission approval for its full AMI deployment funding and schedule in 2005, but the utility then decided to delay the schedule of its deployment activities in order to improve the AMI metering technology and add more functionality.

6.2.3. AMI Cost Recovery

14. How and over what time frame the costs of AMI services are being recouped (i.e. either a regulatory depreciation period or a commercial expectation)?

The costs of implementing AMI services are be recovered through higher approved revenue requirements for the IOUs that are then passed onto the final customers as higher tariffs. AMI is considered part of the IOUs' distribution system and they are entitled to earn a regulatory rate of return on their capital investment. The revenue requirement associated with AMI

137 These may relate to the frequency of meter polling, scalability of IT infrastructure, the amount of data storage in meters versus other collection points in the network, and communications systems needed to support these functions.

138 The working group contains representatives from the CEC and the CPUC.

139 Joint Assigned Commissioner and Administrative Law Judge's Ruling Providing Guidance For The Advanced Metering Infrastructure Business Case Analysis, Rulemaking 02-06-001, Public Utilities Commission of the State of California, 19 February 2004, p. 4.

140 Assigned Commissioner and Administrative Law Judge's Ruling Calling for a Technical Conference to Begin Development of a Reference Design, Delaying Filing Date of Utility Advanced Metering Infrastructure Applications, and Directing the Filing of Rate Design Proposals for Large Customers, Rulemaking 02-06-001, Public Utilities Commission of the State of California, 24 November 2004, p. 1.

takes into account a regulatory depreciation period. Depreciation expense is defined as the charge against earnings that the IOU takes each year to allow for the recovery of AMI investment (including removal costs) over its useful life.

In the different phases of filing AMI applications, all three utilities (PG&E, SDG&E, and SCE) have asked for funding for pre-deployment activities related to AMI, including testing of AMI technologies, developing demand response and dynamic pricing programs with additional benefits, and evaluating Requests for Proposals on AMI.

Customers of the utilities will initially pay for the implementation of AMI through increased revenue requirements. However, the AMI cost-benefit analysis presented by the PG&E and SDG&E show that operational savings (shorter power outages), more effective customer service and new services (i.e. online access to energy-usage data and demand response appliances) will offset most of the AMI investment and O&M costs in the early years. Over time, the benefits of demand response – namely the reduction in procurement-related costs due to new rate programs, plus reduced operational costs and greater efficiencies in metering and network control due to AMI, are expected to more than offset the forecast annual AMI revenue requirements.[141, 142]

In the case of PG&E, these savings will cover roughly 90% of the cost to deploy and operate the system over its 20-year life.[143] More than half of these savings result from the elimination of manual meter-reading activities. Other primary areas for operational savings include billing, remote connect/disconnect, metering operations and outage restoration. The SmartMeter program is expected to pay for itself over the projected life of the system.

6.3. Roles of Market Players

15. What are the roles and responsibilities of (1) distributors; (2) retailers or (3) intermediaries and the extent to which each has been primarily or solely responsible for AMI arrangements?

The CPUC and CEC have put California IOUs in charge of implementing AMI. It is the sole responsibility of the IOUs to see that this initiative is achieved. The costs of implementation are assigned to the IOUs' distribution networks. The distributors are free to hire additional help to assist them in this task.

141 SDG&E estimates the up-front capital expense of the overall system at about $500 million, with overall savings to customers outweighing costs over the 32-year life of the smart meter system by $60 million to $65 million. SDG&E's Smart Meter Program, http://www.sdge.com/smartmeterv2/benes.shtml, accessed 15 April 2008.

142 Over five years, PG&E will roll out its SmartMeter program at a cost of US$1.7 billion. The incremental revenue requirement requested by PG&E to pay for the AMI Project is approximately a 1% increase to PG&E's combined gas and electric revenue requirement. Source: Application of Pacific Gas and Electric for Authority to Increase Revenue Requirements to Recover the Costs to Deploy an Advanced Metering Infrastructure, Application No. 05-06, Public Utilities Commission of the State of California.

143 Pacific Gas and Electric Company Seeks to Implement Advanced Meter Reading Technology for All Customers, PG&E News Release, http://www.pge.com/about/news/mediarelations/newsreleases/q2_2005/050616a.shtml, accessed 15 Apri 2008.

16. Who owns the meters and communication infrastructure?

All IOUs own the meters and communication infrastructure.

17. Who installs the meters?

The distributors either install the meters on their own and/or hire others to assist in the installation process.

18. Who maintains the meters?

The IOUs are responsible for maintaining the meters. They generally hire special contractors (Field Service Representatives, or FSRs) to support meter replacement activities, as meter failures occur throughout the deployment period.

19. Who operates the communication infrastructure?

The three IOUs operate the communication infrastructure through a subcontractor.

IBM serves as the system integrator for the SCE program (Edison SmartConnect™), managing the development and integration of network management and meter data management.

PGE's SmartMeter program currently includes two separate communication systems: a radio frequency (RF) system for gas (Hexagram's STAR system) and a power-line carrier (PLC) system for electricity (DCSI's TWACS system).

SDG&E is still finalizing its contract agreements with meter vendors and communications providers.

20. Who provides, accesses and processes data?

21. Who are the parties involved in these services and on what basis have the roles been allocated between the parties involved in AMI services?

22. If applicable, how is interoperability between different AMI services and between different operators/providers ensured?

The three IOUs sub-contract with entities specialized in provision of meter data management systems and support for customer billing, energy information and utility operations.

Each IOU is ultimately responsible for all AMI services. SMUD and LADWP are starting to implement AMI although they are not regulated by the CPUC, and they are responsible for all AMI services within their territories.

6.4. Progress to Date

23. What has been the progress to date?

The three IOUs have filed final AMI applications with the Commission, for full-scale deployment of AMI. The Commission has already approved the full-scale deployment strategies of PG&E and SDG&E, while SCE's approval is still pending.[144] A Commission decision on SCE's AMI case is expected by mid-August of 2008.

The specific deployment schedule and penetration as per each IOU's filing is detailed in the answer to question 25.

24. When and where were policies set out? When did the implementation of the policy begin, if at all?

See responses to questions 10 and 11.

25. What is the extent of AMI penetration?

Except for SCE, whose AMI application is still pending, the CPUC has approved AMI deployment for all customer classes of PG&E and SDG&E. SCE expects to deploy Edison SmartConnect™ meters to all residential and business customers under 200 kW. More details and progress to date, by IOU, are given below.

6.4.1. PG&E

PG&E's goal is to install SmartMeter™ electric and gas meters for all customers by 2012. By the end of 2011, it will deploy approximately 10.3 million new meters at nearly 6 million homes and businesses across PG&E's 70,000-sq mile (181,300-sq km) service area. It also will deploy a communications network and back-end IT systems capable of collecting and processing hourly electric and daily gas usage data.[145]

In the fall of 2006, PG&E and Wellington Energy, an authorized, independent contractor for PG&E, began upgrading gas and electric meters in the Bakersfield area, after receiving CPUC approval in July 2006. In the spring of 2007, PG&E expanded deployment to Sacramento, California, where it is deploying gas modules. PG&E exceeded its goal of completing 242,000 meter upgrades by the end of 2007. As deployments spread to other parts of the utility's service area of northern and central California, meter installation is intended to ramp up to a rate of 12,000 meters a day.[146]

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[144] The CPUC Decisions regarding the three IOUs´ filings for full scale deployment and pre-deployment activities are: PG&E: D0607027 (full deployment), D0509044 (pre-deployment); SDG&E: D0704043 (full deployment), D0508018 (pre-deployment); SCE: D0707042 (Phase II, pre-deployment), D0512001 (Phase I, pre-deployment).

[145] PG&E Begins Ambitious AMI Rollout, Transmission & Distribution World, http://tdworld.com/customer_service/pge_begins_ami_rollout/, accessed 1 May 2008.

[146] PG&E Begins Ambitious AMI Rollout, Transmission & Distribution World, http://tdworld.com/customer_service/pge_begins_ami_rollout/, accessed 1 May 2008.

In December 2007, PG&E began billing a first set of customers on usage data collected remotely through the SmartMeter system. As billing on SmartMeter data becomes operational for additional customers, manual meter reading for these customers will be discontinued.

PG&E's SmartMeter system is one of the first to build a meter data-management system (MDMS) and an enterprise-level energy-usage data warehouse as integral parts of its AMI system architecture. The MDMS is engineered for multiple collector networks as PG&E fully anticipates multiple field technologies will be used given the size, breadth and diversity of its service area. The first two field technologies are PLC for electric and RF for gas, but MDMS was designed from the beginning to accommodate others. To allow for future applications and services as they are developed, PG&E implemented service-oriented architecture principles in the design of system interfaces where beneficial. Initial deployment of these systems began in November 2007.

PG&E is looking to upgrade the current SmartMeter technology with solid-state meters that include both built-in remote connect/disconnect switches and devices for remotely communicating into the premises. These devices would allow PG&E to provide a greater range of capabilities than the electromechanical meters currently in use.

6.4.2. SCE

SCE plans to roll out SmartConnect meters for all SCE customers and small businesses during a five-year period. Full scale deployment is targeted to begin in 2009 and will be completed in 2012. Starting in January 2009 and ending in 2012, SCE plans to deploy Edison SmartConnect™ meters to all residential customers located in 5.3 million households and all business customers under 200 kW (approximately 5.3 million meters) throughout the 50,000-square-mile service territory at an average rate of about 6,000 meters per work day across multiple separate regions simultaneously.[147]

6.4.3. SDG&E

In early April of 2007, the CPUC approved SDG&E´s AMI project to implement its Smart Meter Program. SDG&E will begin replacing an estimated 1.4 million electric meters and retrofitting approximately 900,000 gas meters throughout its service area in fall 2008.[148] SDG&E already has smart meters at about 7,200 businesses. SDG&E plans to finish the AMI implementation for all customers by the spring of 2011.

6.4.4. Other Utilities in California

SMUD and LADWP are not regulated by the CPUC but both utilities have started to implement AMI. Starting in 2004, SMUD started introducing new “AMR drive-by” meters (meters that can be read automatically by wireless communication with vehicles driving past the premises) with a goal of completing a full installation by the end of 2009. However, since

[147] SCE Smart Connect Deployment Funding and Cost Recover, Errata to Volume 2: Deployment Plan, Before the Public Utilities Commission of the State of California, 5 December 2007, p. 12

[148] Smart Meter Program Receives State Approval, SDGE EnergyNews @ Work, June 2007.

deployment started, advanced metering costs decreased about 30%, and the benefits of enhanced monitoring, demand response applications and other benefits to the utility made SMUD change its plans. SMUD now plans to change all 600,000 meters, including the 150,000 drive-by meters that will be installed in its service territory, with advanced meters at an estimated cost between US$75 million and US$90 million.[149]

LADWP has already started installing AMR (automatic meter reading) for the majority of its residential customers; however, it plans to take a different approach to the deployment of AMI for these customers. LADWP plans to implement a targeted installation of AMI to about 10% of its residential customers. The targeted group will include its largest residential customers based on monthly energy use and its 3,000 or so critical care customers, who need a reliable source of energy. LADWP has already had a business case approved by its board for this deployment strategy and plans to borrow the money needed to pay for the project, which should pay back over the long run, with benefits outweighing costs. LADWP may increase its percentage of residential customers with AMI as the technology becomes less expensive.[150]

26. What proportion of customers and, in particular, of residential customers have received smart meters?

Currently, the only IOU residential customers who have smart meters are those who were selected as part of testing.

§ SDG&E residential customers who have SmartMeters installed are customers located in Fallbrook, Claremont and downtown San Diego, which were the three cities chosen in SDG&E's August 2006 Major Field Test.

§ PG&E installed 2500 SmartMeter electric meters and 2500 SmartMeter gas meter modules at homes and businesses in Vacaville, California, as part of technology testing in 2006. By the end of 2007, PG&E had exceeded its goal of completing 242,000 meter upgrades.

§ SCE's field testing started with Field Test 1 in 2006, a pre-deployment activity that includes the installation of as many as 5,000 Edison SmartConnect™ meters for residential users.

§ LAWDP has installed AMI SmartSynch meters in all of its large commercial and industrial customers that have monthly demand greater than 500 kW. In addition, LAWDP has installed AMI in about 30% of its medium-sized customers with monthly demand between 30-500 kW. Currently, the only residential customers with AMI are the test group.[151]

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149 Advances in smart metering steer Burbank, SMUD, to big deployments, one with WiFi, *Platts Electric Utility Week*, 29 October 2007.

150 Based on a conversation NERA had with George Chin who works in LADWP's AMI Department. 1 May 2008.

151 Based on a conversation with George Chin, of LADWP's AMI Department, 1 May 2008.

7. New York

7.1. New York Energy Market Background

1. Are energy businesses (generation, retail, networks) privately or state owned or controlled?
2. What is the extent of vertical integration in the market between (1) generation, wholesale trading and retailing (2) generation/wholesale and transmission networks and (3) retailing and distribution networks?
3. How many distribution networks are in the market?
4. How many retailers are in the market? Do they serve the whole retail market in this jurisdiction or just part of it (e.g. some customer groups, some areas only)?
5. Are retail markets for electricity (and gas, if applicable) open to competition, for some customers or all (if some, which)?
6. What are the entry conditions of the retail market and other relevant markets?

New York's energy businesses are privately owned and retail markets are open to competition for all customers for the purchase of gas and electricity. In May 1996, New York began restructuring what had been a vertically integrated electric utility industry. The New York Public Service Commission issued an order that required investor-owned utilities to file restructuring plans. NYISO (New York Independent System Operator) was proposed at that time to assume operational control of the investor-owned utilities' transmission assets. By the end of 1999, retail access had been implemented throughout New York State.[152]

NYISO directs the operation of the New York State power system. It is responsible for facilitating transmission services and ancillary services. "The NYISO procures sources of power and certain ancillary services through open markets that it administers….In doing so, the NYISO facilitates open access to the NYS transmission system, provides non-discriminatory access for all Market Participants, and allows meaningful involvement by Market Participants in the operation of the NYISO."[153] It holds auctions for a day-ahead market (conducted prior to the commencement of each day) as well as a real-time market (conducted when the load actually occurs) to determine market-clearing prices based on participants' bid data. Most energy in the NYISO is transacted in the day-ahead markets.[154]

Transmission owners operate and maintain the transmission system. There are eight transmission owners in the New York system. New York's transmission capacity is open to all market participants "on an open access and non-discriminatory basis."[155]

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152 Nicolai Sarad and Dean Colucci, "The Competitive Market for Power in the U.S.: The Role of ISOs and PXs," DLA Piper US LLP. http://library.findlaw.com/2000/Mar/1/127779.html

153 NYISO Market Participants User's Guide, NYISO, 29 March 2007, p. 2-1.

154 NYISO Market Participants User's Guide, NYISO, 29 March 2007, p. 2-1.

155 Nicolai Sarad and Dean Colucci, "The Competitive Market for Power in the U.S.: The Role of ISOs and PXs," DLA Piper US LLP. http://library.findlaw.com/2000/Mar/1/127779.html

Generators schedule and operate generation resources, and they are capable of selling energy, capacity, and ancillary services. New York has about 332 generating plants owned by approximately 170 entities.[156] "Generators may transact in the centralized wholesale power exchange implemented by NY-ISO, and may compete in distinct markets for energy, installed capacity, and ancillary services….The generator is paid the market clearing price, not its bid price, at the point it supplies energy to the system and the purchaser paying [sic] the market clearing price at the point it receives energy from the system."[157]

Power Marketers buy and sell power. They take possession of the purchased energy and arrange transmission services between parties involved. Load Serving Entities (LSEs) or Energy Service Companies (ESCOs) supply energy, installed capacity and ancillary services to retail customers (end-users and wholesale customers). They pay the NYISO for energy and ancillary services, and contract independently for installed capacity.[158] "LSEs include the competitive retailers (CRs) that sell electricity at retail in the competitive market."[159] There are more than 100 ESCOs in New York State, some of which serve only residential or business customers. "In each of the service territories of the six major combined utilities, at least six electric and six gas ESCOs are actively serving customers."[160]

"Ancillary services support the transmission of energy and reactive power from supply resources to loads and are used to maintain the operational reliability of the NYS power system. More specifically, the ancillary services refer to services provided by generators, demand side resources, other system equipment, and services provided by NYISO. One of the NYISO's main responsibilities is to facilitate the ancillary services market."[161]

7.2. Policy of Government/Regulatory Authorities

7. **What is the policy of the Government and/or the regulatory authority in relation to AMI?**
8. **Are there any laws/decrees or other provisions that concern AMI? Can you provide a brief summary of their content?**
9. **What is the nature or extent of regulatory intervention in AMI arrangements?**
10. **Have regulatory authorities mandated the deployment of AMI or left it to the market? Who is directly paying for AMI?**
11. **Have regulatory authorities enacted specific regulatory provisions to mandate, facilitate or incentivise the deployment of AMI?**

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156 Energy Information Administration (EIA), Form EIA-860 Database for 2006. http://www.eia.doe.gov/cneaf/electricity/page/eia860.html

157 Nicolai Sarad and Dean Colucci, "The Competitive Market for Power in the U.S.: The Role of ISOs and PXs," DLA Piper US LLP. http://library.findlaw.com/2000/Mar/1/127779.html

158 Aaron Westcott, New York Independent System Operator, Generation Perspective Market Training.

159 http://www.ercot.com/services/rq/lse/index.html

160 State of New York Public Service Commission, Case 07-M-0458, Proceeding on Motion of the Commission to Review Policies and Practices Intended to Foster the Development of Competitive Retail Energy Markets, 18 April 2007, p.4. http://www3.dps.state.ny.us/pscweb/WebFileRoom.nsf/Web/3E9C4BBE489453EA852572C700499791/$File/202_07M0458OrdFin2.pdf?OpenElement

161 NYISO Market Participants User's Guide, NYISO, 29 March 2007.

Historically, New York has had something of a patchwork of programs related to the deployment of advanced metering technology. Although New York has never mandated smart meter rollouts, it does offer incentives to large customers to participate in demand response programs that require the installation of such meters.

"[The New York Energy Research and Development Authority, (NYSERDA)] helps ensure that New York State uses its energy resources wisely, economically, and in an environmentally sound fashion."[162] "[NYSERDA] and the New York State Public Service Commission are encouraging users of electricity throughout New York State, particularly in the New York Metro area, to participate in demand response programs offered by the New York Independent System Operating and Transmission Owners. In order to measure and verify demand reduction, smart meters or interval meters are a key component to program participation….Purchase and installation of smart meters may also qualify for reimbursement offered through NYSERDA's Peak-Load Reduction Program."[163] Through the New York Energy $mart program, NYSERDA offers incentives for buildings to install interval meters. According to the program fact sheet, participants may receive funding of up to $1,500 per meter.[164]

With participation in these demand response programs, "[a] wide range of options is available to help customers acquire and successfully use smart meters:

- Buy and install your own meter
- Buy only the data others obtain for you from the smart meter
- Build your own system for tracking and using your new information, and
- Select consultants to interpret the data for you."[165]

Then-Governor Eliot Spitzer outlined his administration's commitment to supporting smart metering during his 2007 State of the State Address. In the associated fact sheet regarding the "Smart Metering Initiative," the Governor acknowledged that a challenge for New York's energy market is that "[a]dopotion of the Smart Metering technologies in the market today is limited to installation of interval meters in support of time-sensitive hourly rates for the State's largest commercial and industrial customers."[166]

In describing New York's approach to facing such challenges, the Governor described a "15x15" initiative, whereby "new technologies, including Smart Meters, should be considered to empower customers with information that will help them conserve energy and

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162 "A Primer on Smart Metering," New York State Energy Research and Development Authority, Fall 2003, p. 4.

163 "Smart metering makes sense: NYSERDA offers saving tips," Real Estate Weekly, 13 August 2003. http://findarticles.com/p/articles/mi_m3601/is_/ai_107204504

164 Peak-Load Reduction Program, New York Energy $mart, Public Service Commission, NYSERDA, fact sheet. http://nyserda.org/programs/peakload/incentivechart.asp

165 "A Primer on Smart Metering," New York State Energy Research and Development Authority, Fall 2003, p. 1.

166 "State of the State Address Fact Sheet: Smart Metering," State of New York, Executive Chamber, Eliot Spitzer, Governor, 9 January 2008.

use energy more efficiently."[167] Furthermore, the Governor pointed out that "[t]he PSC has already directed electric utilities to file comprehensive plans for the development and deployment of advanced metering systems, where feasible and cost effective, for the benefit of all customers. These plans are under review. Four of the six investor-owned utilities filed Smart Metering proposals calling for replacing 6.67 million meters at an average installed cost of $158 per meter. The PSC is considering the minimum features and functions of a general Smart Metering program. The PSC has directed certain utilities to develop pilot programs, and in the next several months will decide whether other utilities should fully deploy Smart Meters in their service territories." The current status of the PSC's efforts to develop a plan for smart meter deployment is discussed below.[168]

Volatility in the energy market coupled with supply disruptions and increasing demand for electricity are pushing New York towards having to incur great expense to upgrade its transmission, distribution, and generation facilities. The PSC views smart metering as a potential option for relieving some of the pressures on the energy system.[169] Previous policy had been "based upon expectations that the competitive market would spur the development of advanced metering,"[170] but it has become necessary for New York to adopt "a policy that relies upon electric distribution utilities to install the necessary advanced metering infrastructure to realize the State's energy policy goals. Accordingly, electric utilities were directed to file comprehensive plans for development and deployment, to the extent feasible and cost effective, of advanced metering systems for the benefit of all customers. Gas utilities were directed to assess the feasibility of developing, offering, and installing advanced metering systems for large volume gas customers."[171]

According to a phone interview on 2 May 2008 with Martin Insogna, staff contact at the New York State Public Service Commission, the development and deployment plans submitted by electric utilities (their response to the State's request) revealed that regulators and market participants were all working from different understandings regarding smart metering. Once this fact came to light, the Commission endeavoured to establish minimum functionality recommendations for metering technology so that utilities would have a starting point for thinking about rolling out their own smart metering programs.

To date, the Commission's efforts to establish minimum functionality requirements have involved issuing a request for comments, receiving comments from several market participants, and holding a technical conference to discuss functionality with market participants (April 2008).[172] Mr. Insogna explained that they are currently reviewing the transcripts of the conference to determine next steps, which will include substance (i.e.,

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167 "State of the State Address Fact Sheet: Smart Metering," State of New York, Executive Chamber, Eliot Spitzer, Governor, 9 January 2008.

168 "State of the State Address Fact Sheet: Smart Metering," State of New York, Executive Chamber, Eliot Spitzer, Governor, 9 January 2008.

169 Advanced Metering Initiative, New York Public Service Commission. http://www.dps.state.ny.us/AMI.htm

170 Advanced Metering Initiative, New York Public Service Commission. http://www.dps.state.ny.us/AMI.htm

171 Advanced Metering Initiative, New York Public Service Commission. http://www.dps.state.ny.us/AMI.htm

172 A transcript of the technical conference held in April can be found here: http://www.dps.state.ny.us/webcast_sessions.htm.

actually developing some standards based on work to date) and process (i.e., how to proceed with establishing minimum functionality standards).

Mr. Insogna believes it is unlikely New York will take steps to legislate or regulate smart metering. The current effort regarding electric utilities developing deployment plans is an attempt to get the utilities to communicate with regulators about what would be most cost effective. He believes there will be no additional incentives beyond the cost savings the utilities could realize by implementing smart metering in their regions, and there will be no penalties for utilities that fail to roll out the technology.

Questions 12-26

Given the limited deployment and progress of smart metering in New York, the other questions are either not applicable or relevant.

8. Ontario

8.1. Ontario Energy Market Background

8.1.1. Overview of Sector Structure

1. **Are energy businesses (generation, retail, networks) privately or state owned or controlled?**
2. **What is the extent of vertical integration in the market between (1) generation, wholesale trading and retailing (2) generation/wholesale and transmission networks and (3) retailing and distribution networks?**
3. **How many distribution networks are in the market?**
4. **How many retailers are in the market? Do they serve the whole retail market in this jurisdiction or just part of it (e.g. some customer groups, some areas only)?**
5. **Are retail markets for electricity (and gas, if applicable) open to competition, for some customers or all (if some, which)?**
6. **What are the entry conditions of the retail market and other relevant markets?**

Historically, Ontario's electricity market was dominated by Ontario Hydro, a state-owned, vertically-integrated monopoly. Ontario Hydro was reorganized into five companies in 1999. The two commercial companies, Ontario Power Generation (OPG, responsible for about 70 percent of Ontario's generation[173]) and Hydro One (transmission), had been intended to operate as private businesses as opposed to crown corporations. So far, efforts to privatise these companies have been blocked.[174]

On 1 May 2002, the wholesale and retail components of Ontario's electricity market were opened to allow full retail access for competition.[175] Competition exists for generation and retailing, but the provincial Government owns the vast majority of generation through its holding in OPG. "While the generation of electricity [is] subject to competition, the transmission and distribution of electricity will continue to be regulated by the Ontario Energy Board. Consumers are able to continue buying electricity through their local utility or from a licensed retailer offering special services."[176] Currently, there are approximately 300 "market participants active in the energy and transmission rights markets" in Ontario.[177] Approximately 54 of those participants are electricity retailers,[178] which are distinct from distribution networks.

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173 http://www.opg.com/power

174 http://www.opg.com/faq.asp

175 Canadian Electricity, Exports and Imports, An Energy Market Assessment, National Energy Board, January 2003, p. 3.

176 Independent Electricity System Operator, FAQs, http://www.ieso.ca/imoweb/mktOverview/mktOverview_faq.asp.

177 Independent Electricity System Operator, Participants, http://www.ieso.ca/imoweb/market/participants.asp.

178 Electricity Retailer – Issued Licenses, Report as of 6 May 2008.

On 11 November 2002, supply uncertainties and subsequent rate volatility lead the Ontario Government to impose a price cap for consumers.[179] Currently, the Ontario Energy Board "establishes the commodity price for electricity payable by low volume customers"[180]; however, consumers can obtain market rates through energy retailers.[181]

Ontario's transmission grid is operated by the Independent Electricity System Operator (IESO), which does not actually own any electric power generation, transmission, or distribution facilities.[182] The IESO was established by the Electricity Act 1998 to be "a non-profit, non-share corporation independent of all other participants in the Ontario electricity industry."[183] It is "responsible for establishing and administering wholesale electricity markets and directing the operation and maintaining the reliability of the integrated power system within the Province of Ontario."[184]

There are over 90 distributors in Ontario.[185] These distributors purchase electricity from IESO's real-time markets. (There is no day-ahead market in Ontario.) Competing offers to sell and, in the case of large purchasers, buy electricity are cleared through the IESO, which balances supply and demand every five minutes. The hourly price charged to distribution networks and some large industrial customers is the average of these five-minute market clearing prices.[186]

All customers are able to participate in Ontario's competitive market. Customers can choose to continue purchasing their electricity from their local utilities, or they can choose to enter into a contract with a retailer at a set rate under a Regulated Price Plan. If they opt to purchase electricity from a retailer, they are still responsible for some charges that may be collected by their local utility.

8.2. Policy of Government/Regulatory Authorities

8.2.1. Regulatory Goals and AMI Legislation

7. What is the policy of the Government and/or the regulatory authority in relation to AMI?

In the Electricity Act 1998, Ontario's Government set out its intention "to ensure the adequacy, safety, sustainability and reliability of electricity supply in Ontario through

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179 Canadian Electricity, Exports and Imports, An Energy Market Assessment, National Energy Board, January 2003, p. 3.

180 Electricity Powers Ontario, Electricity Market Deregulation, http://www.2ontario.com/welcome/oout_515.asp.

181 International Energy Regulation Network, Country Factsheets, Canada, December 2007. http://www.iern.net/country_factsheets/market-canada.htm.

182 IESO, *Meter Data Management and Repository – System Delivery, Request for Information*, Issue 1.0, 27 July 2006, p.1.

183 IESO, *Meter Data Management and Repository – System Delivery, Request for Information*, Issue 1.0, 27 July 2006, p.1.

184 IESO, *Meter Data Management and Repository – System Delivery, Request for Information*, Issue 1.0, 27 July 2006, p.1.

185 http://www.ieso.ca/imoweb/siteShared/local_dist.asp?sid=bi

186 Independent Electricity System Operator, FAQs, http://www.ieso.ca/imoweb/mktOverview/mktOverview_faq.asp.

responsible planning and management of electricity resources, supply and demand; to encourage electricity conservation and the efficient use of electricity in a manner consistent with the policies of the Government of Ontario; [and] to facilitate load management in a manner consistent with the policies of the Government of Ontario," among other stated goals.[187] In accordance with the Electricity Act 1998, the Ontario Ministry of Energy (OME) established the following key initiatives:

§ "introducing flexible, time-of-use pricing for electricity;

§ targeting to reduce Ontario's projected peak electricity demand by five percent by 2007;

§ committing to install a smart electricity meter in 800,000 homes and small businesses by the end of 2007 and throughout Ontario by 2010; and

§ introducing legislation to enable implementation of the Government's smart metering initiative and conservation targets."[188]

8.2.2. Regulatory Policy Provisions for Deployment of AMI

8. What is the nature or extent of regulatory intervention in AMI arrangements?

9. Have regulatory authorities mandated the deployment of AMI or left it to the market? Who is directly paying for AMI?

10. Have regulatory authorities enacted specific regulatory provisions to mandate, facilitate or incentivise the deployment of AMI?

11. Are there any laws/decrees or other provisions that concern AMI? Can you provide a brief summary of their content?

12. Are there any regulatory or industry statements of technical requirements concerning AMI?

13. Where there has been a mandatory deployment, what has been the time frame and any other requirements for the deployment of AMI? What requirements were included in the laws or regulations used to mandate the AMI rollout?

In Ontario, smart metering activities are prescribed by legislation (e.g., Electricity Act 1998 and Bill 21), regulated by the Ontario Energy Board (which was established by and is overseen by the Ministry of Energy), managed by the IESO, and carried out by local distribution networks. As previously mentioned, the Ontario Ministry of Energy set a goal of installing smart meters in 800,000 homes and small businesses by the end of 2007. Ratepayers are funding the Smart Metering Initiative through "adders" (surcharges on electricity bills) designed to compensate distributors for approved activities.

The Government's smart metering initiative requires the smart metering system to include an Advanced Metering Infrastructure (AMI), meter data management / meter data repository (MDM/R) functions, and billing functions for time-based rates. "AMI is the infrastructure within which date- and time-stamped hourly meter reads are to be remotely collected and

187 Electricity Act 1998, S.O. 1998, Chapter 15, Schedule A.

188 Ontario Ministry of Energy, http://www.energy.gov.on.ca/index.cfm?fuseaction=electricity.smartmeters

transmitted daily to a utility's control computer and, eventually, to a centralized MDM/R."[189] The local distribution networks are responsible for AMI installation, operation, and maintenance, and the IESO is responsible for the MDM/R technology.

The Ministry of Energy established the minimum functionality standards for meters, the meter data management and meter data repository, and the target for meter installations.[190] The Ontario Ministry of Energy issued a document entitled, "Functional Specification for an Advanced Metering Infrastructure, Version 2" on 5 July 2007. This document establishes the required minimum level of functionality for advanced metering technology to be deployed as part of the Government's initiative.[191] The Government prohibits discretionary metering activities by distributors under Section 53 of the Electricity Act 1998. This prohibition includes "the installation of smart meters, unless permitted to do so by regulation, a Board order, or Measurement Canada requirements.[192] As discussed below, this prohibition concerning discretionary metering means distributors who undertake metering activities other than those prescribed can be denied cost recovery for such activities.

The Ontario Energy Board provides "the regulatory framework for the smart metering initiative."[193] The Minister of Energy issued a Directive to the OEB on 23 June 2004 that required the OEB "to provide its completed implementation plan to the Minister of Energy no later than February 15, 2005."[194] The Directive established the following criteria for smart meters and associated data systems:

- "A smart meter must be able to measure and indicate electrical usage during prespecified time periods.
- A smart meter must be adaptable or suitable, without removal of the meter, for seasonal and time of use commodity rates, critical peak pricing, and other foreseeable electricity rate structures.
- A smart meter must be capable of being read remotely and the metering system must be capable of providing customer feedback on energy consumption with data updated no less than daily."[195]

Additionally, the Ontario Energy Board has been tasked by the Ministry of Energy with ensuring "that only the prudently incurred costs of implementing and operating smart metering are recovered in rates."[196]

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189 IESO, Meter Data Management and Repository – System Delivery, Request for Information, Issue 1.0, 27 July 2006, p.1.

190 Ontario Energy Board, Report of the Board, Report of the Board on 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, Addendum for Smart Metering Rates, 29 January 2007, p. 8.

191 Functional Specification for an Advanced Metering Infrastructure, Version 2, 5 July 2007, p. 3.

192 Report of the Board, Smart Metering Initiative: Draft Criteria and Filing Guidelines for Smart Metering Pilots, Ontario Energy Board, 25 September 2007, p. 2.

193 Ontario Energy Board, http://www.oeb.gov.on.ca/OEB/Industry+Relations/OEB+Key+Initiatives/Smart+Metering+Initiative+(SMI)

194 Letter from Dwight Duncan, Minister of Energy, to Howard Wetston, Chair, Ontario Energy Board, 14 July 2004.

195 Minister's Directive issued under Section 27.1 of the Ontario Energy Board Act 1998, dated 23 June 2004.

Bill 21, which received Royal Assent on 28 March 2006, "enacted amendments to the Electricity Act 1998 to support the Government's smart metering initiative."[197] This Bill authorised the Minister of Energy to establish a Smart Metering Entity. The Ministry assigned that role to the IESO. The IESO is supporting "the Government's Smart Metering Initiative (SMI) by coordinating and project managing implementation activities. The IESO's Smart Metering System Implementation Program (SMSIP) specifically pertains to the delivery of the [MDM/R] functionality, including all interfaces between the MDM/R and local distribution networks' smart metering and customer information systems."[198]

8.2.3. AMI Cost Recovery

14. How and over what time frame are the costs of AMI services being recouped (i.e. either a regulatory depreciation period or a commercial expectation)?

As previously mentioned, ratepayers are responsible for funding Ontario's smart metering initiative, via the distributors. Because of the enormous cost of implementing the Government's smart metering initiative (including funding for smart meter pilot programs[199]), several distributors would have had difficulty paying for implementation activities up front without financial assistance, because of the normal delay in adding investments to the Regulatory Asset Base (RAB). (Normally, it is only after assets have been incorporated in the RAB that their costs can be recovered.) In response, the Board of Energy's 2006 Generic Decision provided "advance funding in the form of a smart metering rate adder in the years before rebasing. As well as providing advance funding, the adder also phases in the effect on consumer rates that could otherwise arise if the cost of the meters was brought into the rate base all at once in a future year. The rate adder is removed once smart meter asset balances are included in approved rate base and their costs incorporated into a re-based revenue requirement."[200]

The Ontario Energy Board proposed an incentive rate scheme as set out in the "Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors." This scheme would sever the relationship between costs incurred by the utility and the rates it charges, thus allowing the utilities to realise increased margins for operating efficiently. "Further, capital additions made during the period of the incentive rate plan are included in rates only at the time of rebasing. Smart meters will fall into this category."[201]

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196 Ontario Energy Board, Report of the Board, Report of the Board on 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, Addendum for Smart Metering Rates, 29 January 2007, p. 8.

197 Bill 21, An Act to enact the Energy Conservation Leadership Act 2006 and to amend the Electricity Act 1998, the Ontario Energy Board Act 1998 and the Conservation Authorities Act; Royal Assent, 28 March 2006, p. i.

198 Backgrounder, Smart Metering Initiative, Ontario Ministry of Energy, 26 July 2006.

199 Report of the Board, Smart Metering Initiative: Draft Criteria and Filing Guidelines for Smart Metering Pilots, Ontario Energy Board, 25 September 2007, p. 3.

200 Ontario Energy Board, Report of the Board, Report of the Board on 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, Addendum for Smart Metering Rates, 29 January 2007, p. 11 and 14.

201 Ontario Energy Board, Report of the Board, Report of the Board on 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, Addendum for Smart Metering Rates, 29 January 2007, p. 13-14.

Because discretionary metering activities are prohibited, cost recovery by local distribution networks is subject to final approval by the Ontario Energy Board. "In relation to the acquisition of smart meters, metering equipment, systems and technology and any associated equipment,…a distributor may recover its costs relating to functionality that does not exceed the minimum functionality adopted in Ontario Regulation 425/06….[A] distributor may not recover its costs relating to functionality that exceeds the minimum functionality adopted in Ontario Regulation 425/06…unless the costs are approved by the Board."[202]

8.3. Roles of Market Players

15. What are the roles and responsibilities of (1) distributors; (2) retailers or (3) intermediaries and the extent to which each has been primarily or solely responsible for AMI arrangements?

16. Who owns the meters and communication infrastructure?

17. Who installs the meters?

18. Who maintains the meters?

19. Who operates the communication infrastructure?

20. Who provides, accesses and processes data?

21. Who are the parties involved in these services and on what basis have the roles been allocated between the parties involved in AMI services?

22. If applicable, how is interoperability between different AMI services and between different operators/providers ensured?

The Ministry of Energy is responsible for ensuring the Government's policy objectives are met with respect to the smart metering initiative. It provides oversight and monitoring functions that include "budget review and timely decisions in respect of policy issues and regulations to support and guide implementation."[203]

As the Ministry's appointed Smart Metering Entity, the IESO is the main coordinator and facilitator for implementation of the Government's smart metering initiative. "The [IESO] is responsible for planning, managing and implementing the smart metering initiative…including the development of a database that collects, manages, stores, and retrieves smart metering data. The centralized [MDM/R] will provide a common infrastructure for receiving meter reads from all AMIs in Ontario, process the readings to produce billing-quality consumption data, store and manage data and provide interested parties with access to such data."[204] The IESO also manages activities related to

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[202] Ontario Regulation 426/06 made under the Ontario Energy Board Act 1998, Smart Meters: Cost Recovery, Filed 29 August 2006. http://www.e-laws.gov.on.ca/html/source/regs/english/2006/elaws_src_regs_r06426_e.htm

[203] Backgrounder, Smart Metering Initiative, Ontario Ministry of Energy, 26 July 2006.

[204] Ontario Energy Board, Report of the Board, Report of the Board on 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, Addendum for Smart Metering Rates, 29 January 2007, p. 8.

"procurement, technical specifications, standards and integration with the metering infrastructure and customer information systems owned by local distributors…"[205]

Local distribution networks are responsible for managing the transition to smart metering within their service areas. They may already own and maintain an Advanced Metering Infrastructure. "The AMI includes the hardware from the meter to the controlling computer and the software required to run the AMI system."[206] Under the Government's smart metering initiative, they will continue to own and maintain such infrastructure, as well as take responsibility for installing and maintaining new technology to provide the functionality set forth in the new mandates. The new technology "will support and integrate with the MDM/R and…the Customer Information Systems (CIS) which will receive data from the MDM/R.[207] In addition, distribution networks, Energy Service Companies (ESCs), and Retailers are responsible for billing functions.[208]

8.4. Progress to Date

23. What has been the progress to date?

24. When and where were policies set out? When did the implementation of the policy begin, if at all?

25. What is the extent of AMI penetration?

26. What proportion of customers and, in particular, of residential customers have received smart meters?

By the end of February 2008, over 1.1 million smart meters were installed in Ontario.[209] According to correspondence with the Ministry of Energy on 9 May 2008, that number recently reached the 1.27 million mark, representing "approximately 25% of the low-volume electricity consumers in Ontario."[210]

An example of the progress being made can be found in the Hydro One subsidiary, Hydro One Networks, which is responsible for approximately 1.3 million meters as part of the Government's smart meter initiative. As of February 2007, Hydro One Networks had completed installation of approximately 40,000 smart meters.[211]

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205 Backgrounder, Smart Metering Initiative, Ontario Ministry of Energy, 26 July 2006.

206 Ontario Energy Board, Report of the Board, Report of the Board on 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, Addendum for Smart Metering Rates, 29 January 2007, p. 7.

207 Backgrounder, Smart Metering Initiative, Ontario Ministry of Energy, 26 July 2006.

208 IESO, Meter Data Management and Repository – System Delivery, Request for Information, Issue 1.0, 27 July 2006.

209 Minister's Speeches, Notes for Remarks by The Honourable Gerry Phillips, Minister of Energy, Electricity Distributors Association Annual General Meeting /ENERCOM Conference, Toronto, Ontario, 31 March 2008. http://www.energy.gov.on.ca/index.cfm?fuseaction=about.speeches&speech=31032008

210 Email from Ministry of Energy agent to Patricia Robl (NERA), Subject: Conservation – Smart Metering, 9 May 2008.

211 Hydro One Networks Smart Meter Project Backgrounder, 29 March 2007.

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