Australian Energy Regulator

Review of Expenditure of Queensland & South Australian Gas Distributors: Envestra Ltd (Queensland)

December 2010

Wilson Cook & Co
Engineering and Management Consultants
Advisers and Valuers

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Reply to: Auckland Office
Our ref: 1008
Email: info@wilsoncook.co.nz

17 December 2010

Mr Warwick Anderson
General Manager, Network Regulation North Branch
The Australian Energy Regulator
Marcus Clarke Street
CANBERRA ACT 2601

Dear Mr Anderson,

RE: REVIEW OF EXPENDITURE OF QUEENSLAND AND SOUTH AUSTRALIAN GAS DISTRIBUTORS: ENVESTRA LTD (QUEENSLAND)

In response to your instructions, we have reviewed the gas access arrangement proposal submitted on 30 September 2010 by Envestra Ltd in relation to capital and operating expenditure for its Queensland network in the five-year periods ending FY 2011 and FY 2016 and have pleasure in submitting our report.

Capital Expenditure

The main conclusions to come out of the review in relation to capital expenditure are as follows.

(a) The level and pattern of capital expenditure in the present period is considered reasonable, reflecting continued growth in the period, the deferral of various augmentation projects and the deferral of IT-related expenditure.

(b) The principal expenditure in the next period relates to the mains replacement programme and foreseen growth. Envestra has proposed that its existing mains replacement programme be continued but at a faster rate. Whilst a sound case has been made for the Ipswich network, we consider that the case made for the Brisbane network is not proven and that the expenditure on this programme ought to be reduced.

(c) Other than in these respects, the proposed capital expenditure in the next period reflects a catch-up in mains augmentation work and IT expenditure and other conventional elements and we consider that its prudence and efficiency have been demonstrated adequately for us to recommend its acceptance, subject to the removal of contingency allowances, the reassessment of the rate of capitalisation of overheads and some other adjustments.

Operating Expenditure

The main conclusions in relation to operating expenditure are as follows.

(a) Operating expenditure in total was about 5% less than its forecast level in the present period, with variances in all categories.

(b) The proposed base-year level of expenditure is not considered efficient, based on reported productivity levels and analysis of comparative operating expenditure benchmarks for FY 2009. Accordingly, we have recommended an annual compounding productivity improvement adjustment to apply to the base-year level throughout the next period.

(c) Adjustment is needed in several of the proposed "step changes" and other additional costs, including a reduction in Envestra's proposed savings attributable to reduced leak repairs. The latter is recommended in conjunction with our reduction in the capital expenditure proposed for mains replacement in the Brisbane network.

(d) In relation to the level of unaccounted-for gas to be allowed in the next period, we note that Envestra's metering systems report a level of UAFG in its Queensland networks as a whole of only 0.6% and report only an insignificant level of UAFG in the Brisbane network. We further note that if there are losses on the network in excess of the measured level, then either gas suppliers or Envestra's gas consumers are paying for them already, avoiding the need for a further allowance for UAFG to be included in the proposed expenditure. We therefore recommend a level of UAFG in the next period equal to the level that which the business presently measures, *viz.* 0.6% of gas input for its networks as a whole or, expressed more correctly in quantitative terms, 92.3 TJ p.a.

These recommendations are summarised in section 7 of the main text.

Conclusion

In conclusion, we acknowledge with thanks the assistance of Envestra's staff and of the AER in carrying out this work.

Yours faithfully,

Wilson Cook & Co Limited

Wilson Cook & Co.

Encl.

Review of Expenditure of Queensland & South Australian Gas Distributors: Envestra Ltd (Queensland)

Prepared for the Australian Energy Regulator

By Wilson Cook & Co Limited

Enquiries to Mr J W Wilson

Our reference 1008

December 2010

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Disclosure

Wilson Cook & Co Limited has prepared this report in accordance with the instructions of its client on the basis that all data and information that may affect its conclusions have been made available to us. No responsibility is accepted if full disclosure has not been made. We do not accept responsibility for any consequential error or defect in our conclusions resulting from any error, omission or inaccuracy in the data or information supplied.

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1 Introduction

1.1 Appointment

In June 2009, the Australian Energy Regulator (AER) appointed Wilson Cook & Co Ltd, Engineering and Management Consultants, Advisers and Valuers, of Auckland to assist it with a review of the gas access arrangement proposals submitted by the Queensland and South Australian gas distributors [1] to the AER on 30 September 2010 in relation to their capital and operating expenditure in the present access arrangement period (FY 2007 to FY 2011) and in the next period (FY 2012 to FY 2016). The terms of reference for the work are set out below.

This report deals with the expenditure related to Envestra Ltd's Queensland network. [2]

1.2 Scope of Review

Capital expenditure

We were to review and assess the businesses' capital expenditure proposals and to advise the AER on whether we considered them consistent with a service provider acting efficiently and in accordance with good industry practice to achieve the lowest sustainable cost of providing the pipeline services. In particular, we were to consider:

(a) forecast capital expenditure for the next period; [3]

(b) actual or estimated capital expenditure in the present period relevant for the opening regulatory asset base;

(c) the application of real cost escalators used by the businesses and as adjusted, if required, by the AER; and

(d) adjustments to forecast capital expenditure based on advice that will be provided by the AER following its review of the businesses' demand forecasts.

In making our recommendations, we were to have regard to the factors listed under section 79(2) of the Rules that the AER will be required to consider in making its decisions. Consideration was also to be given to the national gas objective to promote efficient investment in and efficient operation and use of natural gas services with respect to price, quality, safety, reliability and security of supply of natural gas. (We understand in these regards that capital expenditure in the present period will be assessed by the AER under rule 79 of the Rules and where appropriate the criteria in sections 8.16 and 8.17 of the *Gas Code*.

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1 Envestra Ltd in respect of its Queensland and South Australian networks separately and APT Allgas Energy Pty Ltd in respect of its Queensland network.

2 Throughout the report, references to the AER are generally to the management unless the sense requires reference to the Board itself; references to periods are to regulatory (access arrangement) periods unless the context requires otherwise; references to 'Envestra' or to 'the business' are to Envestra Ltd; and references to 'the network' are to Envestra's Queensland network.

3 Under this heading the terms of reference noted, "The review was to consider the justifications and drivers to support the proposed capital expenditure. For example in relation to market expansion or augmentation capital expenditure the reasonableness of the expenditure was to be considered in association with assumptions about the growth in demand; in relation to replacement and renewal capital expenditure the age and condition of the assets was to be considered along with the ongoing operating and maintenance expenditure over the life of the assets".

[4] and that capital expenditure in the next period will be assessed in accordance with rule 79 of the Rules. [5])

With respect to any recommendation under item (b), we were required to provide only a "high level" review of the efficiency of actual capital expenditure, noting any exceptions, and to identify the reasonableness of any estimates where actual data were not available. [6]

Operating expenditure

We were to review and assess the businesses' operating expenditure proposals and to advise the AER on whether we considered them consistent with those of a service provider acting efficiently and in accordance with good industry practice to achieve the lowest sustainable cost of providing the pipeline services. In particular, we were required to consider: [7]

(a) workload escalation factors (including the effects of efficiencies of scale) used to estimate forecast operating expenditure in the next period;
(b) the application of real cost escalators, adjusted, if required, by the AER;
(c) interaction and trade-offs between operating and capital expenditure;
(d) incentives of the service providers to achieve operating efficiencies – in particular, any commercial arrangements for the procurement of services from third parties; and
(e) adjustments to forecast operating expenditure based on advice that will be provided by the AER following its review of the service provider's demand forecasts.

Where past operating expenditure is proposed as the base on which to establish operating expenditure in the next period we were to provide an assessment of the reasonableness of the base-year level of operating expenditure and the appropriateness of any material changes from that level relating to new requirements or other legitimate causes.

In making our recommendations, consideration was to be given to the national gas objective to promote efficient investment in and efficient operation and use of natural gas services with respect to price, quality, safety, reliability and security of supply of natural gas.

Other Requirements

If the proposed expenditure was not considered reasonable, we were to provide an alternative estimate.

Attention was to be focused on the material expenditure components but we were to make any recommendations considered necessary in relation to the overall level of capital and operating expenditure.

Definitions

We noted that the terms of reference did not define 'prudence', 'efficiency' or 'lowest sustainable cost' and so we state later in this report the interpretation of those terms on which we have relied in our assessment. [8]

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[4] '*National third party access code for natural gas pipeline systems*', including amending agreements.

[5] A précis of the requirements of the Rules in relation to capital expenditure was set out in background information provided separately to us by the AER. Both the *Gas Code* and the Rules consider the compliance of expenditure in terms of whether it is needed for maintenance of the safety, integrity or capacity of the services or words to that effect. However, they also list other grounds on which expenditure could be considered compliant – e.g. in relation to revenue exceeding cost or suchlike.

[6] The term "high level" as used here and elsewhere in the report in relation to the review of expenditure is taken to mean an overall review as opposed to a line-by-line review.

[7] The consideration of expenditure items not determined on technical (engineering) grounds, *viz.* carbon costs, debt-raising costs, self-insurance costs and marketing costs, was excluded from our review.

[8] See section 2.1.

Other Matters

We were to advise the AER, if required, on any adjustments needed in the forecast expenditure because of the AER's review of the distributor's demand forecasts but no such request was made.

Although not a written requirement of the terms of reference, we were to liaise with the business during the course of our review including, if necessary, requesting through the AER any additional information or documentation needed and meeting with the business as required.

We were to present our draft reports to the AER by the end of November 2010 and our final reports by 17 December.

1.3 Relevant Material and Consultation

For the purpose of the review, we received and considered the business's proposal and its supporting documents, particularly its proposed *Access Arrangement Information* (AAI), supporting appendices and documents (e.g. internal policies and procedures, technical reports and data) and the report of the relevant jurisdictional regulator for the present period. We sought and received clarifications and additional information from the business in the form of explanations given at our meetings with its staff in Adelaide and Brisbane on 21, 22 and 27 October 2010 and in subsequent correspondence. [9]

We acknowledge with thanks the cooperation of the business's staff in this regard and the comprehensive nature of its documentation.

1.4 Matters Not Reported On

The review was limited to the context of our instructions – specifically, the particular scope of work set out in section 1.2 above.

The following matters were excluded from consideration in our work or were not undertaken:

- review of forecast demand, as that was not within our terms of reference;
- review of the business's policies for the capitalisation of expenditure (although we have commented where thought fit on the **quantum** of some amounts that are to be capitalised in the next period and on some instances where we considered the expenditure not to be capital in nature);
- review or re-calculation of detailed network analyses;
- review of the cost-of-materials or cost-of-labour escalators applied by the business;
- review of expenditure other than that associated with the business's network business unit;
- review of capital contributions; [10]
- physical inspection of the assets;
- recalculation of expenditure if we had reason to consider the projections inappropriate, other than in respect of proposing adjustments for the AER's consideration;
- consideration of the possible effects of the following factors that can only be conjectured:

[9] The business's proposal and supporting documents were received by us on or around 1 October 2010 and responses to our requests for additional information, sent through the AER, were received up to 1 December 2010.

[10] Our assessments relate to gross capital expenditure, not net.

  - requirements for capital expenditure related to future safety issues, new statutory requirements, new Government policies or initiatives, or environmental requirements except to the extent that they have been identified by the business;
  - possible adjustments in capital expenditure stemming from the application of demand management policies other than those already reflected in the business's estimates;
  - any changes from current network planning or design practice;
- review of financial models;
- consideration of the impact of any performance incentives applied to or available to the businesses by or through the AER or its predecessor to achieve operating efficiencies (other than the normal commercial incentives for a business to operate efficiently);
- consideration of the financial or economic effect if any on the business or any other party of the proposed expenditure or our recommended levels of expenditure;
- any matters outside our field of expertise; and
- any other matters identified elsewhere in the report as having been excluded from our work.

We did not attempt to verify the accuracy of the data provided to us or of the statements and representations made by the business. Nor did we carry out an audit of the business's accounts, asset register, data, expenditure, processes or any item or activity or take any action that might be considered to have constituted an audit. We relied solely on the submissions received from the business and the representations made in response to our enquiries.

1.5 Independence and Probity

Wilson Cook & Co Limited and its reviewers are all independent of Envestra Ltd and the AER, other than in the context of providing the AER with professional advice on expenditure matters from time to time.

Whilst the AER's staff provided guidance in respect of our terms of reference and assisted us with our work and whilst we considered their advice and requests, we are satisfied that none influenced our report or its conclusions inappropriately.

2 Definitions and Network

2.1 Definitions

Prudence and Efficiency

The terms of reference do not define prudence or efficiency for the purpose of the review. Therefore, without attempting to interpret the Rules (and except in the case of our assessment of prudence of the business's capital expenditure in the current period – see below), we adopted the following approach.

We first noted that the objective of the review was, in essence, to assess the business's expenditure proposals and to report to the AER on whether in our opinion the forecast expenditure reasonably reflected the efficient costs of a prudent gas distribution business working in the circumstances of the business concerned.

We noted that to ensure adequacy or effectiveness, a prudent operator might undertake more work than otherwise considered necessary but to ensure efficiency it might undertake less and thus a balance between the two is required.

We noted that *prudence* has connotations of exercising sound judgement especially concerning one's own interests, being careful to avoid undesired consequences, being cautious or circumspect in one's conduct, managing carefully and with economy. Prudence is often best judged by the absence of evidence suggesting a lack of it. In the case of gas networks, imprudence might be most discernible if there was evidence of failure to invest adequately, accompanied by identified adverse consequences, and is thus best assessed retrospectively.

Where we considered that there was an appropriate balance between these factors, prudence and efficiency, we have said in the text that we consider the expenditure "reasonable". Where we identified instances of imprudent expenditure, an imprudent failure to make expenditure or of what appeared to be inadequate provision for future expenditure, we have described them.

We considered *efficiency* in terms of the nature or timing of expenditure and looked for evidence that as far as practicable the expenditure reflected optimal planning and design and competitive costs taking account of local factors, 'good gas industry practice' and the defined security of supply and service standards of the business concerned.

Good Gas Industry Practice

We interpreted *good gas industry practice* to be the exercise of that degree of skill, diligence, prudence and foresight reasonably to be expected of a gas distribution business working under the prevailing conditions consistent with applicable regulatory, service, safety and environmental objectives.

Lowest Sustainable Cost

Both the Code and the Rules refer at various places to the "lowest sustainable cost" of providing pipeline services or words to that effect but neither defines these terms. For the purpose of our report, we have interpreted "lowest cost" to mean the cost to the business (and hence to the customer) of implementing the least-cost option of delivering the required services, constructing the facilities necessary to deliver the services, carrying out operational or maintenance activities necessary to deliver the services, maintaining the required level of safety, integrity or capacity of the services or, in short, meeting the applicable statutory and regulatory obligations and requirements as the case may be.

The encapsulation of performance measures as a regulatory obligation avoids the need for us to go into those matters in our review.

After determining the scope of a project or expenditure programme on the basis of demand and other factors, and having identified, quantified, and valued the costs and benefits of the project alternatives, the next step in project assessment is to identify the least-cost or most cost-effective alternative to achieve the purpose of the project. A comparative analysis of the scale, location, technology and timing of alternative project options or designs is often required. Such an analysis will take into account the costs to the business (and thus indirectly the costs to its customers) in testing for least-cost or productive efficiency. Alternatively, if the effect or outcome of a project can be quantified but not valued, the average incremental cost can be estimated with the aim of establishing the project alternative with the lowest per-unit cost. [11]

The costs and benefits considered should be "life-cycle" costs – *viz.* the costs and benefits over the expected life of the project or programme concerned. This ensures that a long-term view is taken of investment requirements.

In this way, the "sustainability" of delivery of the pipeline services (which we interpret to mean sustainable at the required level over time) is inherent in the concept of the least-cost option in that a long-term view is taken when identifying the project requirements (in terms of service capability, capacity or the like), the costs and the benefits of the options available to meet the identified need and the resulting solution.

As can be seen from the preceding text, the concept of least-cost options inherently incorporates the selection of modern designs and technologies and such other features as are in accordance with good industry practice.

2.2 Brief Description of Network

The network originated in about 1864, when the Brisbane Gas Company was formed to reticulate manufactured gas (its operating area was restricted to the northern side of the Brisbane River by the State government in 1889). It now serves about 84,000 customers in North Brisbane, its Riverview zone (which includes Ipswich) and its Northern zone (which includes Rockhampton and Gladstone). [12]

It transports around 4.3 PJ of gas p.a. to 67 large customers who each consume more than 10 TJ p.a. and 1.4 PJ of gas p.a. to the remaining customers, as summarised in Table 2.1.

Growth in the number of connections is forecast by the business to continue over the next period at approximately 2,800 p.a., a rate of increase of 2.6% p.a. [13] Consumption per residential customer is expected to continue to fall (at a rate of 2.6% p.a. over the next period) although the total throughput is expected to increase at approximately 0.6% p.a. [14]

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[11] The use of edited text based on World Bank guidelines is acknowledged.

[12] A map of the network is available on ***www.envestra.com.au***.

[13] Sources: RIN (customer numbers) and the AAI, p.184 (rate of increase).

[14] Sources: AAI, p.184 (residential consumption) and attachment 13.1 (NIEIR), table 7.2 (total throughput).

Table 2.1: Customers and Demand in FY 2010

Customer Category	Number	Percent	TJ p.a.	Percent
< 10 TJ p.a. – Volume Customers (Residential)	80,674	97%	720	13%
< 10 TJ p.a. – Volume Customers (Commercial/Industrial)	2,831	3%	1,252	22%
	83,505	**100%**	**1,973**	**35%**
≥ 10 TJ p.a. – Demand Customers	67	0%	3,724	65%
	83,572	**100%**	**5,698**	**100%**

Sources: RIN (customer numbers) and AAI attachment 13.1(NIEIR), table 7.2 (throughput).
Sums may not add due to rounding.

The extent of the network by location is shown in Table 2.2.

Table 2.2: Network Extent by Location

Location	Length in Service (km)
Brisbane	1,812
Ipswich	278
Rockhampton	229
Gladstone	56
Total	**2,375**

Source: AAI, p. 9.

Gas is delivered via 11 gate stations at Murarrie, Redbank, Riverview, Sandy Creek, Brightview, Rockhampton North, Rockhampton South, Gladstone (Breslin Street), Gladstone (Yarwun), Bundaberg, and Maryborough. [15]

The network operates at four pressure levels as shown in Table 2.3.

Table 2.3: Network Operating Pressures

Pressure	Length in Service (km)
Low	373
Medium	1,812
High	179
Transmission a/	10
Total	**2,375**

Source: AAI, p. 9.
a/ Transmission pressure refers to distribution mains operating at a pressure of greater than 1,050 kPa.

Of the pipeline materials in use, 80.2% (1,904 km) is plastic, 6.7% (158 km) is protected steel and 13.1% (312 km) is unprotected steel and cast iron. [16]

Unaccounted-for gas (UAFG) in FY 2010 was measured at only 80.5 TJ or about 0.5% of receipts at the gate stations. The business notes that this level of UAFG is low and considers

15 Gas supply is taken from the Roma-to-Brisbane pipeline and the Queensland gas pipeline that runs from Roma to Gladstone. From Gladstone, the Envestra-owned Wide Bay pipeline runs approximately 300 km to Maryborough via Bundaberg. This pipeline supplies the networks in Rockhampton, Bundaberg, Maryborough and Hervey Bay.

16 Source: AAI, p. 9.

that it is inconsistent with other networks with similar inventories of cast iron and unprotected steel mains. It claims that its actual level of UAFG is higher and that an estimated 80% of the UAFG from network leakage arises from the cast iron and unprotected steel mains that it retains in service. [17]

Cast iron pipe is suitable for use only at relatively low pressures and thus pipelines of that type have the added disadvantage of limited capacity to meet new demand. In addition, both cast iron and unprotected steel pipelines are prone to increasing rates of gas leakage as they age and their condition deteriorates.

[17] Source: AAI, attachment 7.2 (AMP) p. 27 *et seq.* Slightly higher figures were derived from detailed data provided to us, as indicated and discussed in section 4.2 of this report.

3 Capital Expenditure in Present Period

3.1 Summary of Expenditure

Capital expenditure in the present period is projected to be $95.8 m compared with $81.1 m approved by the QCA in its last decision, an increase of $14.8 m or 18%. A breakdown of the expenditure by category is in Table 3.1. [18]

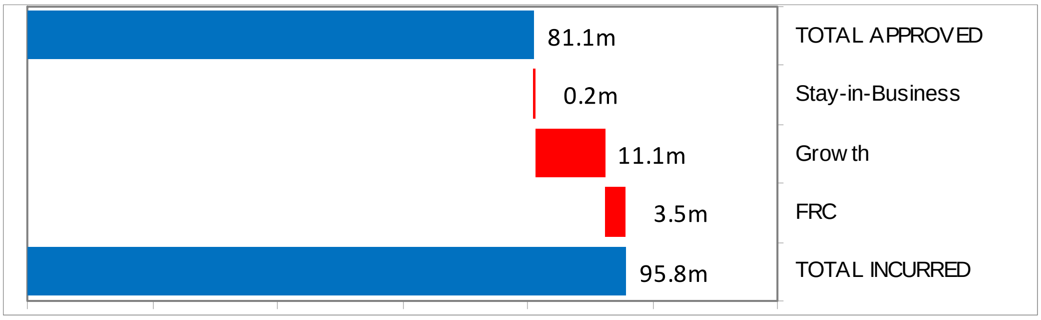
Table 3.1: Capex in Present Period vs. Decision ($2010 m)

		FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	**Total**
Stay in Business	Allowed	8.0	7.5	13.2	7.4	7.4	**43.5**
	Incurred	9.2	5.4	10.0	10.0	9.0	**43.7**
	Variance	1.3	(2.1)	(3.2)	2.6	1.6	**.2**
Growth	Allowed	6.8	6.7	6.1	6.5	6.6	**32.6**
	Incurred	7.2	9.1	8.8	8.1	10.6	**43.8**
	Variance	.4	2.5	2.7	1.6	4.0	**11.1**
FRC	Allowed	8.2	1.8	(5.0)	.0	.0	**4.9**
	Incurred	6.1	2.3	.0	.0	.0	**8.4**
	Variance	(2.1)	.5	5.0	.0	.0	**3.5**
Total	**Allowed**	**23.0**	**15.9**	**14.3**	**13.8**	**14.0**	**81.1**
	Incurred	**22.6**	**16.8**	**18.9**	**18.0**	**19.6**	**95.8**
	Variance	**(.5)**	**.9**	**4.6**	**4.2**	**5.6**	**14.8**
		-2%	**5%**	**32%**	**30%**	**40%**	**18%**

Source: AAI, p. 34, Table3.5 (Incurred), Revised Table 3.6 provided to AER (Allowed).
Figures may not add due to rounding.

Over-expenditure occurred in all three categories, as illustrated by the summary of variances shown in Figure 3.1.

Figure 3.1: Variances by Category ($ 2010 m)



As part of our review, we noted that Envestra had awarded new contracts for service connections and other work commencing in FY 2011. This has resulted in an increase in

[18] The table and the text that follows it differs in emphasis from Table 3.6 in the AAI and the text that follows that table, as the line item "Total Material Changes" in that table has been reallocated to the other categories (by Envestra) in our table. This alters the pattern of movement in each of the line items.

contract labour costs and would have affected its expenditure in the last year of the present period compared with that foreseen by the QCA. [19]

3.2 Growth-Related Expenditure

Envestra forecasts growth-related expenditure of $43.8 m, as shown in Table 3.2. The table shows that that there was an overrun of $11.1 m in comparison with the level approved by the QCA.

Table 3.2: Growth-Related Expenditure in Present Period ($ 2010 m)

		FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	**Total**
Large Consumers	Approved	.1	.1	.1	.1	.1	**.6**
	Incurred	.0	.0	.0	.0	.0	**.0**
	Variance	(.1)	(.1)	(.1)	(.1)	(.1)	**(.6)**
Improved Supply	Approved	.8	.5	.3	.4	.3	**2.2**
	Incurred	.0	.0	.0	.0	.7	**.7**
	Variance	(.8)	(.5)	(.3)	(.4)	.5	**(1.5)**
General Mains	Approved	1.8	1.9	1.7	1.9	2.0	**9.3**
	Incurred	2.7	2.3	3.0	3.5	3.9	**15.4**
	Variance	.9	.4	1.3	1.7	1.9	**6.1**
Regulators	Approved	.1	.1	.1	.1	.1	**.3**
	Incurred	.0	.0	.3	.0	.0	**.3**
	Variance	(.1)	(.1)	.2	(.1)	(.1)	**(.1)**
Meters	Approved	1.0	1.0	.9	1.0	1.1	**4.9**
	Incurred	1.3	1.8	1.4	1.1	1.5	**7.1**
	Variance	.3	.8	.6	.2	.4	**2.2**
Services	Approved	1.6	1.8	1.7	1.7	1.7	**8.4**
	Incurred	3.2	5.0	4.1	3.4	4.5	**20.3**
	Variance	1.6	3.3	2.4	1.8	2.8	**11.9**
Major Projects & Other a/	Approved	1.4	1.4	1.4	1.4	1.4	**7.1**
	Incurred	.02	.00	.00	.00	.00	**.02**
	Variance	(1.4)	(1.4)	(1.4)	(1.4)	(1.4)	**(7.0)**
Total	**Approved**	**6.8**	**6.7**	**6.1**	**6.5**	**6.6**	**32.7**
	Incurred	**7.2**	**9.1**	**8.8**	**8.1**	**10.6**	**43.8**
	Variance	**.4**	**2.5**	**2.7**	**1.6**	**4.0**	**11.1**
		5%	**37%**	**45%**	**24%**	**60%**	**34%**

Source: AAI, p. 34, Table 3.5 (incurred); revised Table 3.6 provided to AER (approved).
a/ The approved amount was for major projects; the incurred amount is for "other" expenditure.
Figures may not add due to rounding.

The table and Figure 3.2 show that the principal over-spending is reported under the headings ‘general mains’, ‘services’ (service connections) and ‘meters’, whilst under-spending is reported to have occurred in ‘improved supply’ and ‘major projects and other’. No details were provided initially of this latter category but, in response to a request from us for clarification, Envestra informed us that:

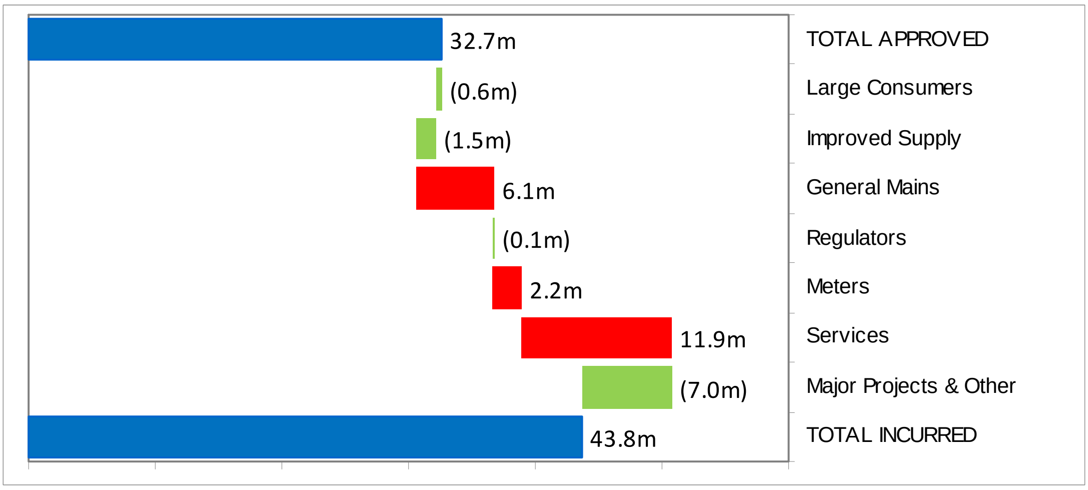
> The “Growth Capex – Major Projects” category was the forecast line for significantly large/major customer connection works, which was forecast separately due to those connections being of a special project nature (as opposed to the voluminous smaller connections forecast under General Mains, Meters and Services).

[19] AAI, attachment 7.1 (capital expenditure and unit rates), p. 1.

> In contrast, Envestra has included the actual expenditure for major connections under the "General Mains", "Meters" and "Services" categories depending on the actual nature of the expenditure. This reflects the requirement for Envestra to allocate such expenditure to the relevant category for the purposes of rolling forward its regulatory asset base. The actual expenditure included in the "Growth Capex – Major Projects" category only contains a minor amount of miscellaneous expenditure.

The effect of combining the general mains, meters, services, major projects and "other" categories is to reduce the reported overrun in these categories to $13.2 m or 44% of the amount approved for these items.

Figure 3.2: Variances in Growth-Related Expenditure by Category ($ 2010 m)



In its AAI (p. 39), Envestra states

> Despite the effects of the GFC, demand for new connections has remained strong due to continued population growth in south-east Queensland, support by Queensland government policy and active marketing of natural gas. This strong growth has contributed to actual capex being greater than that approved by the QCA.

We noted that customer growth anticipated in the present period foresees 5,180 new connections, corresponding to a 17% increase over the period. [20]

New connections for large customers did not reach the forecast level which is not surprising, in the economic climate prevailing at the time.

The categories 'improved supply' and 'regulators' were immaterial and were not investigated.

A more detailed review would be required to confirm the efficiency of the connection work undertaken. However, based on: the facts just cited and taking note of the use of competitively contracted labour; the additional commercial imperative to minimise expenditure that applied in the financial circumstances prevailing in the period; and the documents and explanations we received from Envestra, we are satisfied that the expenditure was reasonable for the work undertaken.

We therefore consider the growth-related expenditure prudent and efficient.

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[20] Sources: ECG Report to the QCA on Envestra, April 2006, table 7-5, p. 68 (Envestra's previous connections forecast); the RIN (connections made); and the AAI, attachment 13.1 (NIEIR Queensland demand forecast), table 6.2, p. 54 (FY 2006 connections).

3.3 Stay-in-Business Expenditure

Details of Envestra's forecast of stay-in-business expenditure of $43.6 m in the present period, are shown in Table 3.3. There is an under-run of $0.2 m in the category with under-expenditure in all categories except "other" which is reported as having been over-spent by $13.3 m.

Of the total expenditure incurred, 87% is accounted for by two categories: mains replacement (52%) and "other" (35%). The remaining 13% is accounted for by the minor categories shown in the table.

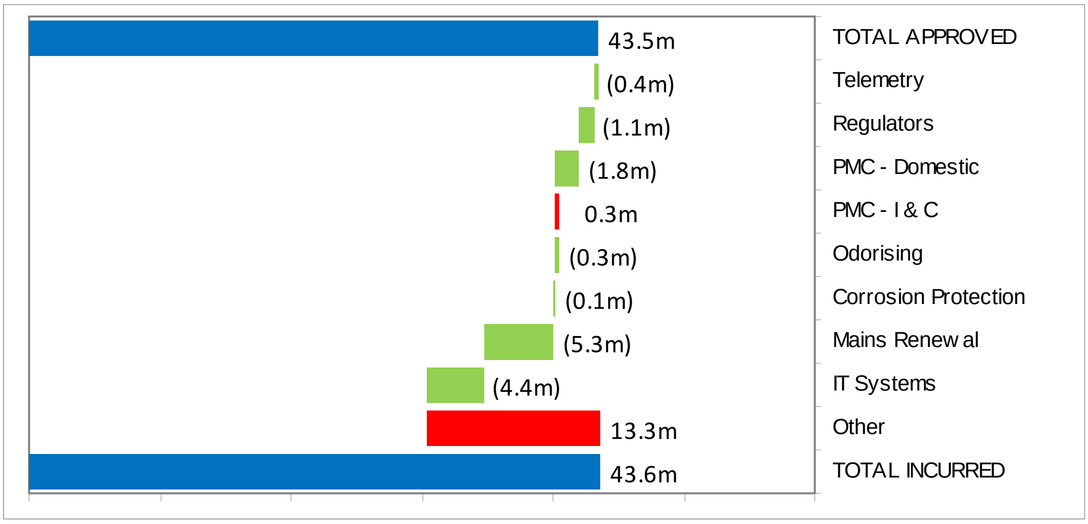
Table 3.3: Stay-in-Business Expenditure in Present Period ($ 2010 m)

		FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	Total
Telemetry	Approved	.1	.1	.1	.1	.1	**.6**
	Incurred	.0	.0	.2	.0	.0	**.3**
	Variance	(.1)	(.1)	.1	(.1)	(.1)	**(.4)**
Regulators	Approved	.3	.3	.4	.4	.4	**1.7**
	Incurred	.0	.1	.1	.2	.3	**.7**
	Variance	(.3)	(.3)	(.3)	(.1)	(.1)	**(1.1)**
PMC - Domestic	Approved	.7	.7	.7	.7	.7	**3.4**
	Incurred	.3	.2	.3	.3	.4	**1.5**
	Variance	(.4)	(.4)	(.3)	(.4)	(.3)	**(1.8)**
PMC - I & C	Approved	.1	.2	.2	.2	.2	**.7**
	Incurred	.1	.1	.2	.3	.4	**1.0**
	Variance	(.0)	(.0)	.0	.1	.2	**.3**
Odorising	Approved	.1	.1	.1	.1	.1	**.3**
	Incurred	.0	.0	.0	.0	.0	**.0**
	Variance	(.1)	(.1)	(.1)	(.1)	(.1)	**(.3)**
Corrosion Protection	Approved	.0	.0	.0	.0	.0	**.1**
	Incurred	.0	.0	.0	.0	.0	**.0**
	Variance	(.0)	(.0)	(.0)	(.0)	(.0)	**(.1)**
Mains Renewal	Approved	5.6	5.6	5.6	5.6	5.6	**27.9**
	Incurred	5.0	3.3	4.4	4.3	5.6	**22.6**
	Variance	(.6)	(2.3)	(1.2)	(1.3)	(.0)	**(5.3)**
IT Systems	Approved	.6	.1	5.9	.0	.1	**6.7**
	Incurred	2.1	.0	.0	.0	.2	**2.3**
	Variance	1.5	(.1)	(5.9)	.0	.0	**(4.4)**
Other a/	Approved	.5	.5	.3	.4	.3	**2.0**
	Incurred	1.7	1.7	4.8	4.9	2.2	**15.3**
	Variance	1.3	1.2	4.5	4.5	1.9	**13.3**
Total	**Approved**	**8.0**	**7.5**	**13.2**	**7.3**	**7.4**	**43.5**
	Incurred	**9.2**	**5.4**	**10.0**	**10.0**	**9.0**	**43.6**
	Variance	**1.3**	**(2.1)**	**(3.2)**	**2.6**	**1.6**	**.2**
		16%	**-28%**	**-24%**	**36%**	**22%**	**0%**

Source: AAI, p. 34, table 3.5 (incurred); revised table 3.6 provided to AER (approved).
a/ Includes mains alterations, misc. plant and equipment, vehicles, misc. office and IT equipment.
Figures may not add due to rounding.

The variances are illustrated in Figure 3.3 by category.

Figure 3.3: Variances in Stay-in-Business Expenditure by Category ($ 2010 m)



Mains Replacement Expenditure

The largest component of stay-in-business expenditure in the present period relates to mains replacement. The projected expenditure on this item is $22.6 m compared with an approved level of $27.9 m – an underrun of $5.3 m or 19%. Envestra states in its AAI (p. 37 *et seq*) that mains renewal capital expenditure was temporarily curtailed from FY 2008 to FY 2010 due to increased funding costs and the need to curtail capital expenditure due to the global financial crisis. Envestra also states that the length of mains able to be renewed "was further impacted as the unit rate approved by the QCA was lower that than necessary to undertake the work".

Relatively little information was provided on the programme but we note that Envestra proposed to replace 344 km of cast iron and unprotected steel pipe over the period but the final allowance was set by the QCA at 250 km with a corresponding rate of progress of 50 km p.a. at a unit rate of $99/m in FY 2006 dollars (around $109 in FY 2010 dollars). [21] Envestra does not disclose the actual length expected to be replaced but based on the difference in pipe inventories reported we estimate it to be around 106 km. [22] Assuming this figure, the average unit rate achieved in the period will be $213 per m in FY 2010 dollars. This rate is considerably above the rate approved by the QCA. However, caution is needed before drawing any conclusions from this comparison as the work is contracted out.

Given the QCA's acceptance of the need for the work and noting the use of competitively contracted labour; the commercial imperative to minimise expenditure that applied in the financial circumstances prevailing in the period; the documents and explanations we received from Envestra, we considered the expenditure prudent and efficient.

'Other' Expenditure

The category called "Other" includes mains alterations, miscellaneous plant and equipment, vehicles, office and IT equipment. The incurred expenditure was $15.3 m, compared to an allowance of $2.0 m – an overrun of $13.3 m. No details were provided initially of this category but, in response to a request from us for clarification, Envestra informed us that:

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[21] Energy Consulting Group (ECG) report on Envestra for the QCA, May 2006, p. 92.

[22] ECG identified 418 km of cast iron and unprotected steel at the commencement of the present period and the AAI (p. 9) identifies 312 km at 30 June 2010.

> The reason for the difference between actual and benchmark "Stay-in-Business – Other" capital expenditure in Queensland was also primarily driven by the higher than anticipated mains alterations work [noting in a previous question response that this category of work is difficult to accurately forecast - especially the quantum of mains alteration works that will be required], but was accentuated in Queensland due to the relatively high economic activity in that state.

Based on the explanation, and noting that the approved level of expenditure implicitly relates to the miscellaneous items cited and is not material in comparison with expenditure in the period as a whole; that the variance is principally accounted-for by mains alterations; and that such work is undertaken either by mandated contractors or using competitively contracted rates, we consider the expenditure reasonable.

Remaining Categories of Stay-in-Business Expenditure

The remaining categories of stay-in-business expenditure include expenditure on telemetry systems, regulators, domestic, industrial and commercial meter changeovers, odorising plant, corrosion protection and IT expenditure excluding expenditure related to the introduction of full retail contestability (FRC). Together, the expenditure in these categories is expected to be $5.8 m in the period compared to an approved amount of $13.6 m – an under-run of $7.9 m.

The biggest reduction was in non-FRC-related IT, where the proposed expenditure of $6.7 m has essentially not been carried out and actual expenditure is projected to be only $2.3 m.

Variances in the other items are immaterial individually and were not reviewed further.

3.4 IT Systems for Full Retail Contestability

The final category in the present period is IT expenditure related to the introduction of full retail contestability. Expenditure was $8.4 m compared to an allowance of $4.9 m – an overrun of $3.5 m.

The capital expenditure on IT systems was to meet the requirements of regulated structural changes in the industry. As this is not a technical matter, we did not review it further.

3.5 Other Considerations

Documented Current Practices

When considering the level of capital expenditure incurred in the present period we took into account Envestra's stated capital expenditure planning and approval processes and its expenditure "governance" processes which are described briefly in the AAI and were explained to us during our meetings with management and staff.

We considered from the documents and our meeting that the business's technical documentation was sound and that its engineering management was knowledgeable in relation to the network and its needs. We considered that the present AMP – we did not review any earlier AMP – was well structured. We noted that it or the accompanying documents included performance levels, a capacity development plan, a mains replacement plan, metering plans and risk assessments. We concluded that the AMP and its accompanying documents to be suitable, in a general sense, for the prudent management of the assets.

However, we noted that, in general, the documents describe the business's present practice, not its practice in the earlier years of the present period or in preceding years. As a result, only inferences can be made from the present documents in relation to practices in earlier years of the present period.

Benchmarking of Capital Expenditure

Envestra includes in its AAI two reports by Marksman Consulting Services in support of its claimed prudence and efficiency in relation to capital expenditure in the period. [23] The first of these – the benchmarking report – includes an assessment of the relative levels of capital expenditure of several gas distribution businesses and concludes that Envestra's levels of capital expenditure over the present period are reasonable from a cost perspective only. Marksman appears to have qualified its opinion in this way as it states that it did not (and was not required to) assess levels of service.

Whilst we acknowledge Marksman's view, we do not normally consider that the benchmarking of capital expenditure is valid, as the networks of the businesses compared usually vary considerably along with the nature of and timing of the capital expenditure requirements in relation to them. This affects the calculation of indicators such as cost-per-customer or cost-per-kilometre of mains or the like.

We observe, also, that Marksman itself notes in its benchmarking report (p.1) that

> Benchmarking needs to be approached with caution as each distributor is unique and will differ from other distributors in its network characteristics, which impacts on the expenditure required."

We have expressed this same view ourselves in previous advice to the AER and to its predecessors.

Independent Audit of Representative Projects

Marksman's second report, the capital projects audit, gives its assessment of 19 capital projects ranging in cost from $5,000 to $4 m, a sample that it considers to be representative of Envestra's capital projects portfolio. It evaluated the projects for prudence and efficiency by assessing, amongst other things stated in its report, the project governance processes that had been applied including whether alternative solutions were considered and economic evaluations undertaken for the projects reviewed.

Marksman states that economic evaluations were carried out in each case that it examined and that cost estimates were based on competitive tenders for large projects and on unit rates (based on completed works) for other projects. Marksman concludes (p.7):

> "Overall, the Consultant considers that the current capital project process has a reasonable level of rigour, supporting the conclusion that past capital expenditure has been prudent and efficient and conforms to National Gas Rules rule 79.

We did not consider Marksman's conclusion that the expenditure conforms to the Rules as that is a matter for the AER to determine.

We did accept, however, that the report presents an independent opinion that, after investigation, the reviewer found the capital projects to be prudent and efficient.

We relied also on the explanations given in relation to the expenditure by the business in its AAI and by the management and staff of the business at the meetings held with them in October.

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[23] AAI attachment 5.8 (*Gas Distributor High Level Benchmarking Report*) and attachment 8.1 (*Capital Projects Audit, December, 2009*).

We further considered that the circumstances in which the business was operating at the time, as noted earlier in this section of the report.

We asked for an explanation of the variances in expenditure by category and received detailed responses to our enquiries.

In essence, we sought, by these methods, to confirm the necessity, optimality and cost effectiveness of the capital expenditure made in the present period and in general, we were satisfied by the information received in these respects.

3.6 Conclusion

We noted Envestra's statement in its AAI (p. 15 *et seq*) that it responded to the global financial pressures during the period by deferring operating and capital expenditure where it was able to do so whilst still operating the network in a prudent manner. It said that the key decisions made were to

> …temporarily curtail expenditure on network development. This was justified on the basis that the immediate impact of making these reductions would be small. However, it was recognised that over the longer term, the impact of such reductions would accumulate, and require additional investment to maintain new connections and gas load; and reduce capital expenditure. The adverse financial conditions required Envestra to reduce capital spend below planned levels. The reduction in capital expenditure was necessary to contain spend [sic]within the available amounts, and in response to the cost of capital for new investment being significantly higher than the return approved by regulators in various access arrangements… Despite the capital constraint, the extent to which capex was curtailed in Queensland was small relative to South Australia because the equity beta approved by the QCA…was higher than that approved by the ESCOSA in SA…providing better returns on investment. Indeed, across the Second Access Arrangement Period, capex in Queensland was almost 20% greater than approved by the QCA.

Envestra considered that, whilst it would have preferred not to curtail expenditure, the actions it took were prudent and represented a rational response to the cost pressures imposed by the global financial crisis. It said that, internally, the changes made were seen as temporary, to be reversed once financial markets reverted to conditions that are more normal.

We recognise, as a general principle, that businesses of this type can make short-term decisions to defer expenditure if needed to conserve cash or for other commercial reasons and that it is often possible to do so without jeopardising the operations materially. However, such situations catch up with businesses eventually and need to be corrected.

We discussed the expenditure during our meetings in Adelaide and Brisbane and we have taken the observations noted above into account in our further reviews in the remaining sections of this report.

Variances in individual categories were significant but Envestra appears to have managed its expenditure carefully, making reductions in discretionary expenditure to reduce the overall level. This was a reasonable and appropriate response in a period when external factors (particularly the global financial crisis) placed the business under financial pressure.

Taking all matters reported in this section into consideration, we conclude that the $95.8 m of capital expenditure incurred or projected to be incurred in the present period as stated in Table 3.1 may be accepted as prudent and efficient by the AER when it considers whether the expenditure ought to be added to the regulatory asset base for the next period.

Our conclusion is based on the expenditure stated in Table 3.1 and does not take account of any revisions that may have been made subsequently by Envestra to that expenditure. [24]

Related Matters

Level of Capitalised Overheads Not Reviewed

We did not review the level of overheads that have been capitalised and included in the estimates discussed in this section of our report.

Capital Contributions Not Deducted

We further note that we did not review any matters related to capital contributions, as they are a revenue matter, not an expenditure matter, and that the expenditure as just stated is gross expenditure, i.e., before the deduction of capital contributions.

Depreciation Not Assessed

Our terms of reference did not ask us to consider the changes that Envestra has proposed in its standard asset lives, although some depreciation will need to be recognised in relation to expenditure that is added to the opening regulatory asset base for the next period.

[24] We were advised on 14 December that Envestra had provided the AER with a revised forecast of the capital expenditure to be incurred in the present period of $80.1 m instead of $95.8 m.

4 Capital Expenditure in Next Period

4.1 Summary of Proposed Expenditure

Capital expenditure in the next period is forecast to be $169.1 m compared with the forecast incurred level in the present period of $95.8 m, an increase of $73.3 m or 77%. A summary of the forecast expenditure is given in Table 4.1. Taken together, the first three items in the table – the replacement of mains and meters and the augmentation of mains – account for 51% the total proposed expenditure in the period and the growth-related expenditure categories account for a further 38%.

Table 4.1: Forecast Capex in Next Period ($2010 m)

FY ->	2011	2012	2013	2014	2015	2016	Total
Mains - Replacement	5.6	14.2	14.4	15.0	15.4	15.6	**74.5**
Meters - Replacement	.8	1.3	1.3	1.4	1.4	1.4	**6.8**
Mains - Augmentation	.7	.6	4.3	.1	.3	.4	**5.6**
Telemetry	.0	.5	.3	.3	.4	.3	**1.9**
Regulators and Valves	.3	.5	.4	.4	.3	.3	**1.9**
IT	.1	2.6	1.4	1.0	.1	.1	**5.2**
Mains - Growth	3.9	3.9	4.3	4.3	4.2	4.5	**21.3**
Inlets - Growth	4.5	6.4	7.1	7.2	7.1	7.6	**35.4**
Meters - Growth	1.5	1.4	1.3	1.1	1.1	1.3	**6.2**
Large Consumers	.0	.6	.4	.1	.1	.4	**1.7**
Other - Distribution System	2.2	1.7	1.8	1.4	1.4	1.5	**7.7**
Other - Non Distribution System	.0	.2	.3	.2	.2	.2	**1.0**
Total	**19.6**	**33.9**	**37.4**	**32.4**	**32.0**	**33.5**	**169.1**

Source: AAI, p. 92, Table 7.1 and RIN. Figures may not add due to rounding.

Basis of the Forecast

Envestra has identified three key drivers of capital expenditure in the next period: asset condition, growth and reliability. It has presented several plans that form the basis of its expenditure forecast – in particular, its *Asset Management Plan*, its *Mains Replacement Plan* and its *Capacity Management Plan* and their various supporting documents.

Together, these documents outline its strategy to replace the remaining cast iron and unprotected steel mains on its network, to augment the network in line with the foreseen growth in demand and to maintain the network.

BIS Shrapnel was engaged to provide an expert opinion about future movements in labour, material and contractor costs in the next period to be applied to its present costs. [25]

In addition, a comprehensive statement on movements in tendered rates has been presented and forms the foundation of the majority of the estimates. [26]

The forecast costs have been split into categories as shown in Table 4.1 above.

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[25] AAI, attachment 6.4 (*Real Cost Escalation*).

[26] AAI, attachment 7.1 (*Capex and Unit Rates*).

Variances from Present Period

Figure 4.1 shows the trend in expenditure in the present period and the next, highlighting the step-up both with and without the mains replacement programme expenditure (labelled "MRP" in the figure). The graphs excluding mains replacement show the impact of its planned acceleration in the next period. They also highlight a "catch-up" in mains augmentation and we discuss these matters later in this section of the report.

Taken together, the movement in the proposed level of expenditure in other categories appears to be broadly in line with the recent trend.

Figure 4.1: Expenditure Trend ($2010 m)

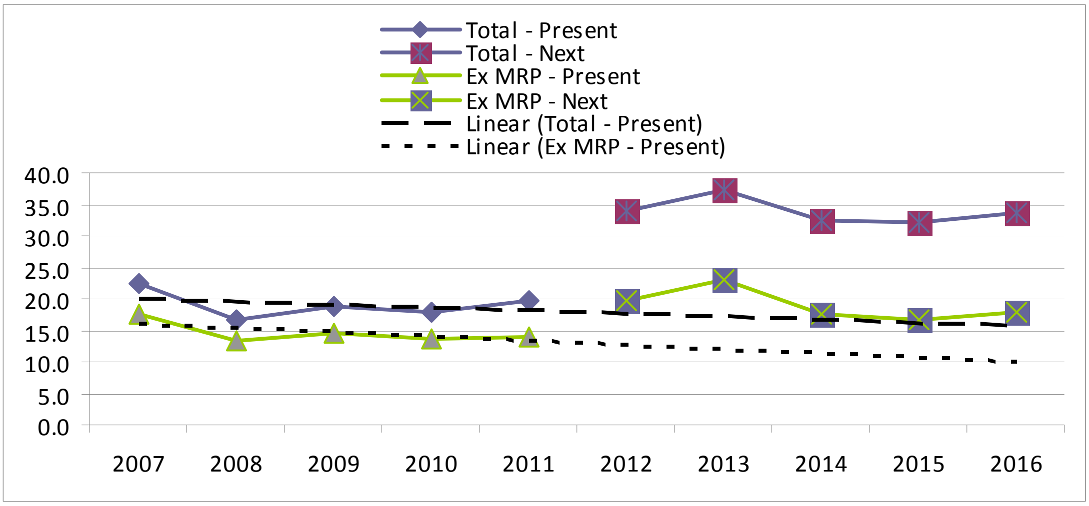
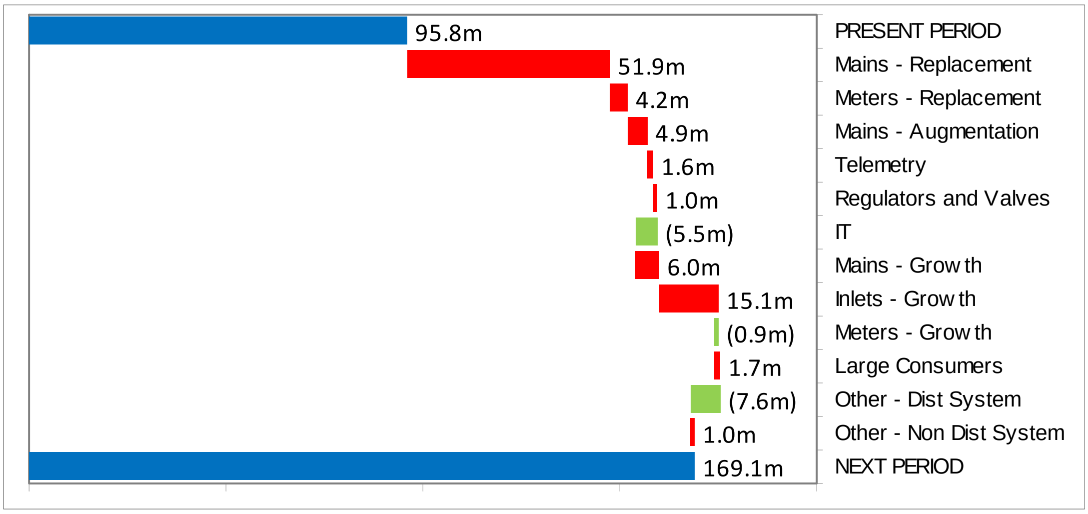


Figure 4.2 shows the contributions of changes in the various expenditure categories to the total increase from the present period and the next.

Figure 4.2: Increases from Present Period to Next ($ 2010 m)



The increase in mains replacement expenditure is the major contributor with an increase over the level in the present period of $51.9 m, followed by the growth categories (which, in total, are projected to be $21.8 m above the level in the present period), augmentation (an increase of $4.9 m), and the remaining categories (a decrease of $5.2 m).

4.2 Mains Replacement Expenditure

Proposed Expenditure

Envestra proposes to spend $74.5 m (accounting for 44% of capital expenditure in the next period) on replacing all its remaining cast iron and unprotected steel mains in the Brisbane and Ipswich networks to reduce gas leakage, reduce repair costs, increase network capacity and reduce the risk inherent in using mains that are in a deteriorated condition. [27] The proposal is described in detail in Envestra's *Mains Replacement Plan,* the executive summary of which we reproduce in full, as it summarises the business's case: [28]

> It is proposed to replace all remaining Cast Iron (CI) and Unprotected Steel (UPS) mains within the Brisbane and Ipswich Networks based on safety risk, inadequate capacity and deteriorating condition and integrity.
>
> It is proposed to replace the remaining 351 km of predominately LP mains over the next 6 years [including FY 2011].
>
> These mains are at the end of their useful lives with the CI mains approximately 75 years old and UPS mains 45 years old.
>
> The prime safety risk concern is associated with gas leaks in high occupancy areas where there is little or no open ground from which gas can vent to atmosphere. Under these conditions, gas could migrate to buildings, plant rooms, etc, in sufficient volumes to create an explosive mixture. The risk is particularly acute within the inner city suburbs of Brisbane and Ipswich.
>
> Over the last few years, the impact of urban consolidation and the use of high instantaneous demand appliances have eroded the spare capacity within the LP Network. The replacement of these mains and upgrade in pressure is considered to provide the most effective and efficient long term solution to this problem.
>
> This mains replacement plan focuses on optimising the use of available CAPEX funds by targeting replacement of mains that:
>
> - Present a high risk to the public and or maintenance personnel
> - Have insufficient capacity to meet current and future consumer demands
> - Incur high maintenance and operating costs.
>
> The following table summarises the replacement program.

	FY 2011	FY 2012-16	Total
Replacement Length (km)	23.5	327.5	351
Cost (Direct) ($M)	3.9	59.8	63.7

> The justification for replacement is based on:
>
> 1. Public and operator safety;
> 2. Meeting regulatory obligations and requirements;
> 3. Maintaining asset integrity and performance; and,
> 4. Reduced operating and maintenance costs over the asset life cycle.
>
> Mains replacement is also shown to be economic, with a real internal rate of return of 10% for Brisbane works and 13.3% for Ipswich works.

In support of this, Envestra claims elsewhere in its *Mains Replacement Plan* that: [29]

- there has been a 68% increase in the number of leak reports received from the public since FY 2006 but changes to the recording systems implemented during FY 2008

[27] Source: *Mains Replacement Plan,* p. 6 *et seq*.

[28] Attachment 7.4 to the AAI.

[29] From pp. 10, 13, 14, 15 and 16 of the Plan.

have contributed to some of this increase, making it difficult (it admits) to infer that the apparent increase is entirely due to the deterioration of mains;

- leakage from cast iron and unprotected steel mains in Ipswich is at about 660 GJ per km p.a. and is consistent with the 620 GJ per km p.a. or so, reported by APT Allgas for its Brisbane network (which, it says, consists of a similar proportion of such mains and is of a similar age);
- 145 km of the old mains are at the end of their life will require replacement on a "piecemeal" basis if "block" replacement is not undertaken; and
- approximately 50-70 km of the old mains have inadequate capacity to meet demand and an increase in operating pressure is needed, requiring their replacement. [30]

In its Asset Management Plan (pp. 27-30), Envestra makes the following additional claims:

> The UAFG in Brisbane has been at relatively low levels over the last 12-18 months despite a significant number of leaks on mains and services.
>
> While there has been a reduction in UAFG over the last 2 years, the current levels are not consistent with UAFG observed in other networks with similar inventories of CI & UPS mains.
>
> Based on the APT Allgas network and Envestra's SA network, CI & UPS mains are considered to contribute 600–1,000 GJ/yr/km to UAFG.
>
> With approximately 220 km of CI & UPS in the Brisbane LP network, these mains would be expected to be contributing between 130 and 220 TJ to the total UAFG.
>
> It is considered that the relatively low UAFG in Brisbane is associated with negative factors counteracting the leakage factor. Further investigations are planned during 2010/11 to establish factors that could be masking the leakage component of UAFG. This will include looking at injection and withdrawal accuracies and the overall metering/billing processes.

Envestra has prepared, for the Brisbane and Ipswich networks separately, economic analyses of the mains replacement investment in which the cost of the planned replacement (which is assumed for the purpose of its analyses to be incurred in the first year) is compared with the present value of (a) the avoided cost of repairs carried out in response to future defects and (b) the present value of the estimated reductions in gas leakage (and some other benefits) [31] that would be achieved if the mains were replaced. A 2% rate of network deterioration is assumed, alternative rates of piecemeal replacement of the 145 km of pipe over both 10 years and 20 years is examined using a 3-times cost multiplier to the block replacement rate and the effect of changes in the assumed level of UAFG is tested. Real cost increases are allowed for, as is inflation, and a discount rate is chosen to match.

Essentially, the analyses compare at a high level the respective costs of planned and deferred maintenance and include the costs of continuing and increasing repairs and leakage expected under each case.

The *Mains Replacement Plan* concludes (p. 21):

> The replacement of the Ipswich CI & UPS network is considered economic on the basis that it is unlikely that the existing UPS mains would have a life beyond 10 years...
>
> **Based on typical leakage rates from other similar CI & UPS networks** it is reasonable to assume that the current underlying UAFG for Brisbane is of the order of at least 150 TJ and that it is unlikely that the existing UPS mains would have a life beyond 10 years... On this basis, replacement of the Brisbane CI & UPS mains is considered economically prudent.

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30 Care is needed in the interpretation of some of these statements and we discuss them further, later in this section of the report.

31 Listed on p. 20 of the *Mains Replacement Plan.*

The *Mains Replacement Plan* includes risk assessments that take into account health and safety risks and risks to business reputation and that reach the conclusions stated in the executive summary. The risk assessments were not quantitative but, in the case of risks that represent rare events, it is common to evaluate them subjectively through an acceptance matrix of likelihood and consequence, as the business has done. [32]

Consideration is given to the need for increased capacity where required to meet existing and future customer loads.

For practical reasons, the analyses assume that replacement would be undertaken in broad "block" areas, consistent with the normal practice of upgrading the operating pressure level of the networks as the replacement proceeds.

The work is to be prioritised to achieve the best combination of benefits.

Conclusions Reached in Previous Regulatory Determinations

This is not the first time that Envestra has proposed significant capital expenditure to carry out mains replacement work. In its submission for the present period, Envestra proposed replacement of 344 km but this was reduced in the final allowance to 250 km and an amount less than this is forecast to be achieved. [33]

In recommending a reduction in the requested rate of replacement, the QCA's advisors, Energy Consulting Group (ECG) concluded:

> ECG therefore believes that **once Envestra renews its highest priority areas, its UAFG should drop considerably. This will reduce the need for Envestra to accelerate its program to remove all of its cast iron mains (including unprotected steel) in five years.** ECG believes that a more realistic timeframe is likely to be something between five and twenty years. On balance, taking the UAFG figure and the age of Envestra cast iron system into account, ECG considers that an eight to nine year program will still achieve the outcomes outlined by Envestra as stated above.

Our Assessment

General Considerations

When assessing the proposed expenditure, we noted Envestra's proposal as summarised above, as further explained in its AAI and the supporting documents and as explained to us at our meeting in October with the business's management and staff.

We further noted the decisions reached in the first regulatory period and in the present period by the QCA, as summarised above. However, we did not feel bound by those decisions as the facts presently applicable may differ from those considered by the QCA and it advisers at the time of the previous regulatory reviews.

We consider that it is the prerogative of a business's owners (or, on their behalf, its directors) to determine the level of risk to which the business is to be exposed although an economic regulator, responsible for reviewing the efficiency of a business that is by its nature is a natural monopoly, may properly wish to be satisfied that the business's decision is reasonable – as we do.

We further note that the justification of expenditure of this type normally rests on a combination of quantitative economic assessment and qualitative risk assessment as well as on practical considerations, such as the following.

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[32] The risk matrices include the other usual categories (e.g. financial impact, customer and business interruption costs, compliance costs) but the level of risk in those categories is considered by Envestra to be moderate.

[33] See section 3.3.

(a) Pipelines of the type under consideration do not last forever and their replacement is inevitable at some time if piped gas supply is to be continued.
(b) The risks associated with pipelines of the type under consideration can reasonably be expected to increase with age (and are shown to have done so, generally).
(c) The physical work involved in their replacement is considerable and, to achieve efficient replacement costs, targets that are consistent over time ought to be set for the replacement work so that the requisite resources – labour and plant in particular – can be marshalled at the outset of the programme and maintained for its duration.
(d) Providing that is done – and providing time is allowed for the volume of work to be "ramped up", there is no technical reason why the replacement work cannot be completed at a reasonable rate.

Application of General Considerations

Need

We were satisfied in general terms that the business had established the need for the work in relation to **Ipswich** (where the measured level of losses is high) but **not** in relation to the **Brisbane network** (where the measured level of losses in effectively zero); and we noted that ECG had also expressed reservations (about the programme proposed for the present period), and considered that UAFG should drop considerably, reducing the need for Envestra to remove all the old mains in the short term.

Economic Return

We reviewed the summarised descriptions of Envestra's economic evaluations presented in the *Mains Replacement Plan* and re-modelled the analyses to the extent possible to satisfy ourselves that their conclusions were reasonable. Several deficiencies were found to exist:

(a) The internal rates of return calculated are understated, as the benefit stream attributable to continuation of supply **after** the point at which the existing pipes can reasonably be deemed unserviceable is excluded.
(b) However, in the case of the **Brisbane** network, the calculation is based on a **conjectured** level of leakage as **no significant leakage is measured in this network**.
(c) The analyses do not calculate equalising discount rates in the normal sense of that term (e.g. as used by the international lending agencies when evaluating investment proposals) as they do not determine the return on the incremental investment between mutually exclusive streams of cost. Instead, they calculate for a wide variety of scenarios comparative returns on the total investment in each. We admit, however, that that may achieve much the same result.
(d) The discount rate used may not match costs escalated over time. If it does not, the result would be to value the cost of capital and the cost reduction due to the benefits unequally, over-stating the return on investment.
(e) On the other hand, Envestra has assumed that all capital investment would be applied in the first year in its comparisons and this will lead to understatement of the benefits.

There is, of course, a wide range of assumptions made and these points need to be weighed up in that respect when determining their significance. Notwithstanding these deficiencies and possible omissions, it is clear that the economic benefits of the **Ipswich** replacement programme are substantial.

Overall, we concluded that the analyses support the business's decision to proceed in **Ipswich**, despite the fact that the benefits of reduced risks and increased capacity were not included in the analyses. They have, however, been qualitatively evaluated and support the expenditure.

Risk Mitigation

It is clear that risks exist in continuing with the leaking mains and that the risks will vary in extent from place to place. *Prima facie*, risks in CBDs will be greater than elsewhere; but risks elsewhere will be accentuated in some situations. However, we note that none of Envestra's proposed replacements are in CBDs.

We noted again Envestra's statement that "approximately 170 km of cast iron and unprotected steel [mains] in Brisbane and 60 km in Ipswich is considered located in high density areas with little open ground from which leaks can vent to atmosphere". [34] We noted that this amount represents 58% of the planned replacement in total. However, we further noted that the statement constitutes principally a description of the area involved, **not** an assessment of risk.

We also noted the various other related statements that we have cited above (such as the 145 km of pipe that is claimed to be at the end of its life and the 50-70 km of pipe that is claimed to pose capacity constraints) and considered that all such statements should be taken together, not treated additively, as there is likely to be at least a degree of overlap in the lengths involved.

Reduction in Gas Leakage

Whilst it is normal to assign a benefit to the reduction of gas leakage, we note that the measured leakage reported in relation to the Brisbane network is, in effect, zero, raising the question of how to ascribe a benefit (other than through reduced risk) to the replacement of mains in that network.

We further note that the movements in UAFG reported in relation to the Brisbane network do **not** show an "abrupt transition" in the period FY 2008 to FY 2009 as claimed by Envestra on p. 32 of its AAI, when seen in the context of the three-year history of UAFG presented on p. 14 of the *Mains Replacement Program*. We reproduce the history in Figure 4.3 below. The figure shows, instead, that gas leakage from the Brisbane network has been declining more-or-less steadily over the period.

Figure 4.4 shows the history of UAFG over the last 13 years for all of Envestra's Queensland networks taken together. [35] It confirms the steady decline in losses. (The figures are dominated by the Brisbane network, because of its size in comparison with the other networks involved.)

Gas leakage from the Ipswich network is a different matter, its level being reported consistently over recent years at around 14% of gas input, as shown on p. 13 of the *Mains Replacement Plan.*

[34] *Mains Replacement Plan*, p. 16 and its executive summary.

[35] *Asset Management Plan*, p. 27.

Figure 4.3: UAFG in Brisbane Network (FY 2007 to FY 2010)

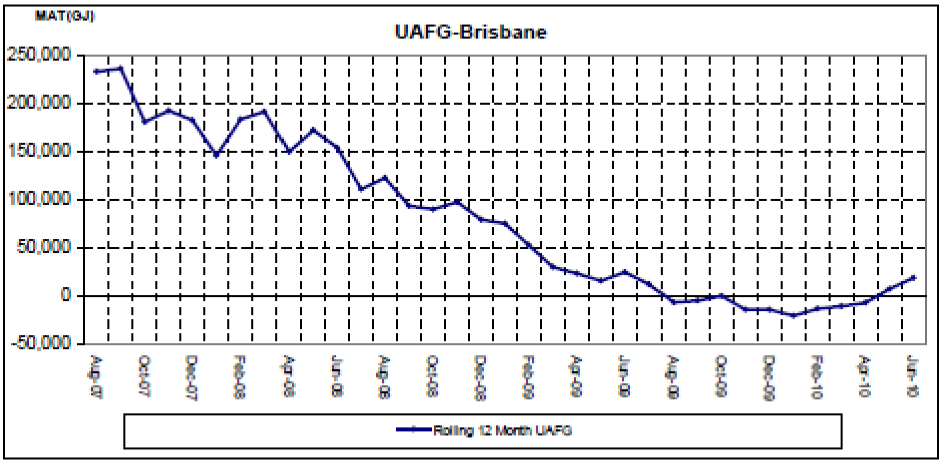

Figure 4.4: UAFG History for Envestra Queensland (All Networks)

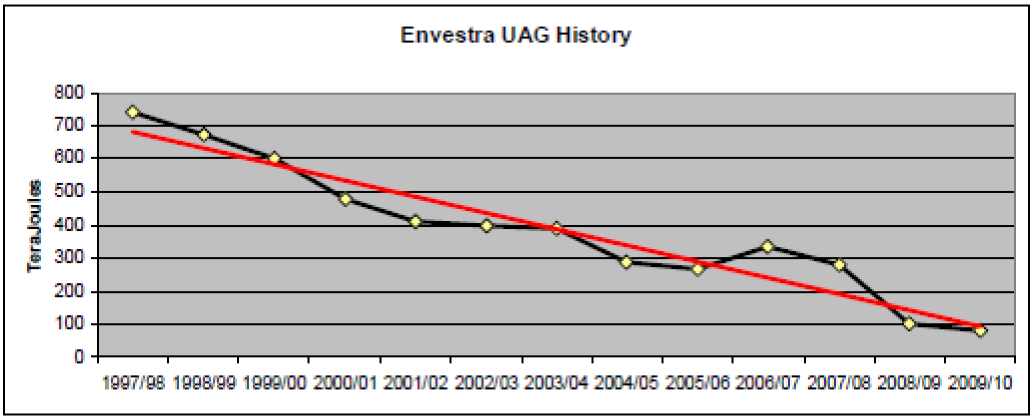

Table 4.2 summarises the UAFG measured, by network. The table shows that 83% of present losses are attributable to the Ipswich network and that the remaining 20% are attributable to the Brisbane network but the **measured** level of losses in the Brisbane network is effectively zero, being equivalent to only around 0.1% of gas input.

Table 4.2: Gas Sales and Leakage by Network

Network	Sales in FY 2010 (TJ)	UAFG in FY 2006	UAFG in FY 2007	UAFG in FY 2008	UAFG in FY 2009	UAFG in FY 2010	Share of UAFG in FY 2010
Brisbane	14,267	1.5%	1.7%	1.0%	0.2%	0.1%	**20%**
Gladstone	30	0.3%	0.1%	1.1%	-5.2%	-3.8%	**-1.2%**
Redbank-Ipswich	526	11.3%	12.8%	16.4%	14.8%	14.6%	**83%**
Ipswich-Riverview	477	0.6%	0.2%	0.8%	-0.3%	-0.1%	**-0.4%**
Lockyer Valley	125	-3.4%	-5.3%	0.9%	-1.3%	-1.2%	**-1.6%**
Rockhampton	209	-3.4%	-1.7%	-4.2%	-1.9%	-0.2%	**-0.4%**
	15,634	1.8%	2.0%	1.5%	0.7%	0.6%	**100%**

Source: Envestra.

It would be possible to conjecture (in relation to the Brisbane network) that leakage will occur in cast iron and unprotected steel mains that are claimed to be in a deteriorated condition and it would be possible to calculate a theoretical level of losses by that method. Envestra has made such a calculation, assuming leakage of 660 GJ per km of old mains p.a.

[36] However, the adoption of a theoretical level of losses derived by this method would be at odds with the (effectively) nil measured level of losses on the Brisbane network.

A related consideration is that if there are losses on the networks in excess of the measured level, then either gas suppliers or gas consumers are paying for them already thus avoiding the need for a further allowance for UAFG to be included in the proposed expenditure.

Table 4.2 further shows that there is no clear trend of increasing leakage on the networks although that could be possible in respect of Ipswich, as a decline in leakage in the last two years could be attributable to the mains replacement work undertaken on that network.

Timing

We reviewed the proposed timing of the expenditure, noting that the business proposes to increase the replacement rate from 24 km in FY 2011 to 66 km in the first year of the next period if the full programme proceeds. Although this suggests that time might not have been allowed to marshal the resources required, we note that the proposed annual length to be achieved in each year of the next period is not large in comparison with that contemplated by Envestra for its South Australian network and on balance we considered that there was no reason to doubt the business was capable of achieving the replacements at the planned rate. [37]

Estimated Cost

The estimated cost of the work is the product of its proposed volume in the period and forecast unit rates. We note that the implied average rate for the work is $228 per km in FY 2010 dollars ($74.5 m divided by 327.5 km) and this is slightly more than the average unit rate achieved in the present period of $213 per m in FY 2010 dollars. However, caution is needed before drawing any conclusions from this comparison as the work is contracted out, there has been a significant, reported uplift in contracted rates for the type of work involved, and a detailed assessment of unit rates for all the types of work involved – which we discuss in section 4.6 of this report – suggests that the rates proposed by Envestra are reasonable.

Conclusion in Relation to Expenditure

After considering these factors – in particular, that the business claims that portions of the network planned for replacement have safety risks and coincident under-capacity associated with them, that the business has identified benefits through a reduction in leak repairs and the reduction of UAFG (the latter being established by measurement **solely in relation to Ipswich**) but that the business has **not** demonstrated to our satisfaction an increasing trend in leakage rates, nor has it demonstrated any link between its assessment of leakage and risk in the Brisbane network and nil measured gas leakage from that network; and noting further ECG's view and the business's own deferral of mains replacement in the Brisbane network in the present period – we concluded that the proposed replacement programme in **Ipswich** is prudent and efficient but that the planned replacement programme in the **Brisbane network** is so **to only a limited degree**.

We further noted that if the replacement programme in the Brisbane network were to proceed, any benefits attributable to reduced UAFG in that network because of such work would **not** be able to be measured.

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[36] This assumption is based in turn on a comparison of leakage reported in networks with similar quantities of old mains: see the *Mains Replacement Plan,* p.14 for details of the comparison.

[37] Envestra is planning to undertake 140 km of mains replacement in South Australia in FY 2012.

Whilst are no measurable benefits possible in terms of reduction in UAFG in the **Brisbane** network, we accept that (a) a level of risk does exist and (b) that there is a capacity issue in some parts of that network.

Accordingly, we recommend that the programme be reduced to include the replacement work in Ipswich and **half** the planned replacement work in the Brisbane network, the latter reflecting our assessment of a reasonable amount between an upper bound (equal to the level proposed by Envestra) and a lower bound of nil replacement, matched to the measured nil measured level of losses in the area. We consider that this level should be adequate to address issues of capacity and risk on the Brisbane network.

Table 4.3 summarises our calculations and indicates the lengths and associated costs for the work that we recommend as prudent and efficient.

This recommendation is subject to the reasonable application of real cost escalators and the reasonable apportionment of capitalised indirect costs, which latter we discuss in section 4.7 of the report. [38]

Corresponding Adjustment to Savings in Operating Expenditure

The reduction proposed by Envestra in its operating expenditure because of the proposed investment in mains replacement should be reduced to match the recommended reduction in the size of the programme. We consider that 83% of the reduction should be accepted (as that is the proportion of measured gas leakage attributable to the Ipswich network) and that half of the remaining 17% ought to be accepted to reflect the recommended level of replacement work in the Brisbane network. This corresponds to acceptance of 91.5% of Envestra's proposed reduction and the cancellation of the remainder. An adjustment in operating expenditure is recommended accordingly in section 6.7 of this report.

Level of UAFG in Next Period

With regard to the level of UAFG to be allowed in the next period, we note again that Envestra's metering systems reported a level of UAFG in its Queensland networks of only 0.6% of gas input in FY 2010 (see Table 4.2) and report no material leakage from the Brisbane network.

We further note again that if there are losses on the networks in excess of the measured level, then either gas suppliers or Envestra's gas consumers are paying for them already, avoiding the need for a further allowance for UAFG to be included in the proposed operating expenditure.

We therefore find no reason to recommend a level of UAFG in the next period that is greater than the level that the business presently measures, *viz.* 0.6% of gas input for its networks as a whole as measured in FY 2010 – or, expressed more correctly in quantitative terms, UAFG of 92.3 TJ p.a.

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[38] There do not appear to be any general contingency allowances incorporated in the estimate but, if there are, then they also should be removed.

Table 4.3: Adjustment of Mains Replacement Programme

FY ->	2011	2012	2013	2014	2015	2016	Total
Expenditure Proposed by Envestra	5.6	14.2	14.4	15.0	15.4	15.6	**74.5**
Lengths Proposed for Replacement (km): a/							
Ipswich	21.5	16.5	16.5	16.5	16.5	16.5	**82.7**
Brisbane Network	2.0	49.0	49.0	49.0	49.0	49.0	**244.9**
	23.5	65.5	65.5	65.5	65.5	65.5	**327.6**
Direct Cost ($ m): a/							
Ipswich	3.5	2.7	2.7	2.7	2.7	2.7	**13.5**
Brisbane Network	.4	9.2	9.2	9.2	9.2	9.2	**46.0**
	3.9	11.9	11.9	11.9	11.9	11.9	**59.5**
Recommended Expenditure							
Lengths Recommended (km):							
Ipswich		16.5	16.5	16.5	16.5	16.5	**82.7**
Brisbane Network		24.5	24.5	24.5	24.5	24.5	**122.5**
		41.0	41.0	41.0	41.0	41.0	**205.1**
Adjusted Direct Cost ($ m):							
Ipswich		2.7	2.7	2.7	2.7	2.7	**13.5**
Brisbane Network		4.6	4.6	4.6	4.6	4.6	**23.0**
Adjusted Total Cost ($ m): b/		8.7	8.9	9.2	9.4	9.5	**45.7**
Reduction ($ m)		**5.5**	**5.6**	**5.8**	**5.9**	**6.0**	**28.8**

a/ MRP, p. 23.
b/ Pro-rated. Includes overhead cost allocation and real cost escalation.

4.3 Growth-Related Expenditure

Envestra proposes $64.5 m of growth-related expenditure in the next period, compared to $42.7 m in the present period, an increase of 51%.[39] The areas included are growth-related expenditure on mains, inlets (*viz.* service connections to customers), meters, connections to large customers and on a sub-category called "other distribution system". Expenditure under this latter category accounts for 38% of the proposed capital expenditure in the next period.

The AAI states that the forecast expenditure for new mains, inlets and meters has been calculated from the product of the connection numbers derived in its demand forecast and its forecast unit rates. A review of the demand forecast was outside the scope of our work but we reviewed the composition of the forecast unit rates set out in attachment 7.1 to the AAI. The unit rates were within the range we expected.

In addition to the expenditure required to serve new customers the category includes the forecast cost of new or upgraded connections to large customers.

Of this expenditure, $21.3 m is attributable to mains, $35.4 m to services, $6.2 m to meters and $1.7 m to connections to large customers. An outline of the work proposed is given in section 7.6.7 of the AAI.

The AAI states that Envestra has estimated the average length of mains (based on historical average) required to extend the network "per customer" in three scenarios: new housing estates, domestic load in established suburbs and industrial-and-commercial load in established suburbs. It has estimated the cost of mains needed to supply demand customers from the forecast demand and it has forecast the number of new connections.

[39] The comparison may not be entirely valid, as expenditure sub-categories may have been grouped differently.

The numbers of services and meters involved are based on the projected increase in the number of connections and the unit rates appeared to have been applied to those quantities.

A review of the forecast increase in demand and in connection numbers is outside the scope of our work and so we restrict our comments on demand-driven expenditure under these categories to the reasonableness of the unit rates that the business applied to the forecast volumes of mains, services and meter work.

According to the AAI the mains component in the case of volume customers is calculated by dividing the total historical length of mains installed by the number of customers connected in the same period to derive the average length of main extension per connection. Based on the data in the AAI and its attachments, the average length of mains appears to range from 3 to 15 metres depending on customer class and is within the range we would expect.

The unit cost per connection is the average for the class of customer, recognising that the cost will vary from connection to connection, depending on pipe length, terrain and locality.

Meters and connections to large customers make up the remainder of the expenditure. We understand that the cost of meters includes not only the cost of the meter itself but also a regulator and a meter box. The unit rates set out in attachment 7.5 to the AAI for this work are within the range we would expect.

Without having checked all calculations, we are satisfied in broad terms that application of the stated unit rates to the volumes derived from the demand forecasts matches the proposed expenditure in the case of volume customers.

In the case of large customers, we did not attempt to verify these costs because of their special nature but note that the total expenditure involved is immaterial.

We discuss the unit rates further in section 0 of this report and in subsequent sections.

Conclusion

In conclusion, we were satisfied that the proposed growth-related work is prudent in scope and timing, based on the business's forecast demand (which we did not review), subject to the removal of contingency allowances of 10% from the cost of services.

4.4 Mains Augmentation Expenditure

Envestra proposes to spend $5.6 m on mains augmentation in the next period. Expenditure under this category accounts for 3% of the proposed capital expenditure in the next period.

Envestra states in section 7.6.3 of its AAI in relation to this expenditure:

> The capital expenditure forecast for the next period provides for: (a) reinforcement of those sections of the network that are vulnerable to gas supply problems, as well as improvements to reduce the likelihood of outages occurring. A comprehensive plan has been compiled that will deliver a high level of reliability, consistent with good industry practice and with the expectations of consumers; (b) augmentation to ensure that the network is capable of continuing to supply the demand for services, particularly in areas of high growth; and (c) augmentation to ensure the availability of high pressure gas in a manner that supports the systematic and planned replacement of low pressure mains.

The processes used by Envestra to identify and evaluate augmentation projects are set out in attachment 7.3 to the AAI, *Capacity Management Plan,* and we reviewed those processes.

We discussed the projects with Envestra staff and reviewed the business cases for the eight augmentation projects involved (listed in Table 7.4 of the AAI), noting that each provided a justification for the project (mainly, that if no action is taken, based on network analysis, pressures in parts of the network will drop below an acceptable level), the options considered and the cost-benefit analysis. [40]

We considered the expenditure prudent and efficient.

Conclusion

In conclusion, we were satisfied that the proposed augmentation work is prudent in scope and timing based on the evidence that Envestra provided (which was based, in turn, on its network analyses). However, we consider that the expenditure should be adjusted to remove the 8% contingency allowance included in all estimates except those for the Sandgate project and "recurrent-reactive" augmentation.

4.5 Other Expenditure

The remaining expenditure in the next period amounts to $24.5 m or 14% of the total forecast capital expenditure in the period. It is made up of meter replacements ($6.8 m), telemetry ($1.9 m), regulators ($1.9 m), IT systems ($5.2 m), "other" distribution system expenditure ($7.7 m) and "other" non-distribution system expenditure ($1 m).

Meter Replacements

The proposed expenditure of $6.8 m on meter replacements is summarised on pp. 94 and 95 of the AAI. It is comprised of three items: domestic meters ($2.7 m), industrial and commercial meters ($3.0 m) and industrial and commercial rectification ($1.1 m). In its AAI, Envestra states:

> Envestra is required to periodically change gas meters in order to test them for metering accuracy. These periodical meter changes (PMCs) take place at intervals (approximately 10-15 years) in accordance with a Measurement Scheme under the Queensland Petroleum and Gas (Production and Safety) Act 2004. This continuous changeover and testing program ensures that each gas meter continues to operate within prescribed tolerances.
>
> The numbers of meters requiring changeover are reflective of the age and types of meters in service. As these factors are well documented and tracked, the forecast quantity has a reasonable degree of certainty, although the recent introduction of a new Australian Standard for meter testing is likely to result in shorter meter field life in coming years. [41]

To comply with the Petroleum and Gas (Production and Safety) Act 2004, a *"Gas Measurement Plan"* has been prepared by APA for Envestra's Queensland distribution networks in Queensland. [42] The Plan addresses, *inter alia*, meter accuracy meter replacement policies and meter maintenance practice.

A meter-testing regime is set out and a meter changeover programme is carried out in accordance with its requirements. A list of meters in service by type and number is provided in Appendix 1 of the *Gas Measurement Plan* but a breakdown by age is not provided.

Given the lack of information on meter ages, we are unable to verify the annual volume of meters to be replaced as proposed by Envestra. However, we note that according to the Asset Management Plan (p. 104) meters with a capacity less than 25 m^3/hr (i.e. domestic and small industrial and commercial customers) have to date had their "lives extended up to 22 years in the field" while larger meters have a fixed life of 10 years. According to the customer

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[40] A cost-benefit analysis was not provided for the reactive augmentation project but the expenditure involved on it is immaterial (around $0.5 m) and so we did not examine it further, other than to note that it appeared justified.

[41] AAI, p. 94.

[42] We note that the *Management Plan* (p. 17) also covers a number of meters owned by Origin Energy.

number forecasts in the AAI (p. 189) there are approximately 80,000 domestic customers, just under 3,000 small industrial and commercial customers and just under 60 demand customers. Based on these numbers and the lives noted above for the two categories the estimated annual volumes of meters to be changed during the next period set out in Attachment 7-6 "Capex Forecast" are in the range we would expect.

We applied unit rates to the forecast numbers and confirmed that the costs are as proposed in the AAI.

In addition to programmed meter replacements Envestra proposes to undertake two upgrading programmes involving meter stations in the CBD and industrial and commercial meter set upgrading. Justification for this work is set out in Business Cases Q14 and Q26 and includes upgrading to current safety and operational standards.

We consider the proposed expenditure reasonable.

Telemetry

The forecast expenditure of $1.9 m on telemetry is immaterial and so we did not examine it further, other than to note that it appeared justified.

Regulators and Valves

The forecast expenditure of $1.9 m on regulators and valves is not material but we did note that, according to Envestra, the proposed work includes: on-going replacement or refurbishment of 45 underground regulator stations to improve access for maintenance personnel, security of supply and to replace equipment in poor condition (Business case Q25); the replacement of damaged lids on access to a number of underground regulator stations (Business case Q16); and the replacement of valves on the Ipswich network that cannot be operated or are leaking (Business case Q07).

We consider the projects justified and the expenditure reasonable.

IT Systems

The forecast expenditure of $5.2 m on IT systems relates to equipment and systems that we consider normal for a business of this type. They include periodic replacement and upgrading of hardware and software and the completion of new systems for works management, advanced asset management and field data capture. Envestra's planning for IT systems appears to be robust and reviewed independently. We consider the capital expenditure prudent and efficient but comment further in section 6.9 on the need for the resulting benefits to be considered in the operating expenditure projections.

"Other" Distribution System Expenditure

Six small expenditure items in the category named "other" distribution system expenditure total $7.7 m and have been proposed by Envestra to maintain network integrity. They are listed and discussed on pp. 101 and 102 of the AAI and comprise:

(a) mains alterations (applies where pipelines are located on private land or in areas where easements cannot be obtained or the location is unsuitable);
(b) the replacement of aged regulators in conjunction with periodic meter changes;
(c) replacement of odorising stations.
(d) the replacement of pipes laid in sleeves under railways;
(e) replacement of non-compliant meter installations:
(f) replacement of shallow mains.

Details of the work, including justifications and cost estimates, are provided in the AAI and in five of the six cases in business cases attached to the AAI.

We consider the above projects justified and the expenditure reasonable except for a 20% general contingency allowance included in the estimate for the sleeved railway crossings.

"Other" Non-Distribution System Expenditure

Forecast expenditure of $1.0 m is proposed under the heading "other non-distribution system expenditure". The AAI (p. 102) identifies it as comprising the replacement of essential tools, plant equipment and other similar items. We consider that the expenditure appeared prudent.

4.6 Cost Estimates and Unit Rates

The cost-effectiveness of the work reviewed in the preceding parts of this section of the report rests heavily on attachment 7.1 to the AAI. This attachment discusses the make-up of the costs applied to work under various headings, such as mains in new estates, mains to existing homes, mains to industrial and commercial premises, service connections (inlets) to new homes, the periodic-meter-change programme and mains replacement. [43]

The attachment comprehensively sets out the basis of the various cost estimates and their efficiency. It is clear from it which rates are contracted, which have internal cost elements and which vary with volume. The extent to which individual rates have increased in recent years is also clear. A more detailed analysis in given in the spreadsheet in attachment 7.5 to the AAI.

None of the rates listed appears to include a general contingency allowance except the rates for services.

We satisfied ourselves that the rates so stated are, to the best of our knowledge, carried through into the estimates.

We note that the rates discussed are before the application of indirect costs, overheads and, in some cases already identified in this section of the report, general contingency allowances.

4.7 Contingencies, Escalation and Indirect Costs

Contingencies

It is normal to add contingency allowances to estimates that are put to a board of directors for approval of capital expenditure but we do not consider it appropriate for non-specific contingency allowances to be added to expenditure estimates in regulatory submissions for the following reasons.

(a) The allowances constitute, in effect, a provision.
(b) Whilst a contingency allowance may need to be called upon in some instances, such allowances are unlikely to be called upon generally, or to their full extent; and to argue that they would is to say, in essence, that the business concerned is unable to estimate its costs accurately or that it does not wish any risk of cost overruns to remain.

Provisional sums that are included in cost estimates to deal with specific matters that will arise but which cannot be quantified are a different matter and should be treated on their merits. [44]

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[43] Reference to "block" mains replacement is to the replacement of an area.

[44] One such example has been identified and discussed in section 4.4.

A further point is that the normal business risks that a network business ought to bear (and that are reflected in the permitted cost of its capital) should not be transferred to users. This is particularly important in a monopolistic situation where the regulator has a role to play as surrogate for a market, thus preventing a cost-plus culture prevailing in the monopoly service provider with its accompanying inefficiencies.

We would expect Envestra to have sound forecasting and budgeting processes, to refine them periodically and to be capable of producing estimates that prove, in the event, to have been accurate.

Based on the material provided (which does not establish the need for contingency provisions) and the points made above, we see no reason why any general contingency or other such general allowance ought to be agreed to for Envestra's capital expenditure.

We do not have sufficient information to calculate the amount to be removed, although we have estimated it in section 4.9. We suggest that the business should be asked at an appropriate time to re-state its expenditure forecast without contingency allowances.

Real Cost Escalation

Envestra has applied escalators to its capital expenditure forecasts to reflect expected increases in its costs in real terms. Their application is set out in the attachment 7.6 to the AAI (*Capex Forecast - September 2010*).

Envestra states in its AAI (p. 84 *et seq*) that real cost escalators for the next period were provided by its consultant, BIS Shrapnel; that each forecast item has been split as general labour, electricity-gas-and-water labour, network materials (mainly polyethylene piping), general materials and, in relation to capital expenditure, contract labour for the construction sector. Forecast costs have been split into these categories in accordance with an average of historical expenditure. The escalators are applied in each year of the next period.

We note that the escalators have been derived independently and generally accord with our understanding of cost movements in the gas sector. However, we have not assessed their quantum, only their method of application; and we consider the latter reasonable in terms of the percentages to which the various escalation factors have been applied.

Indirect Cost Allocations

Indirect costs (overheads related to capital works) have been added to the direct costs of most capital works at a rate of 20%. A lower rate, 10%, is used for the large mains replacement and augmentation programmes to recognise economies of scale in their planning and management. [45] Envestra states,

> An analysis of the actual overheads incurred over the past three years has been undertaken and reveals that an average overhead rate of 20% is required to recover these costs.
>
> Envestra has adopted the historical 20% overhead rate as a default forecast of overheads. However, a more conservative forecast of 10% has been used to forecast overheads for the mains replacement and augmentation expenditure. The lower rate recognises the expanded capital expenditure program in this proposal.

It is normal for indirect costs associated with putting new fixed assets into service to be recognised as a cost component and added to the regulatory asset base and information provided to us by the AER on 1 December suggests that the nature of the expenditure that Envestra plans to capitalise is in accordance with such a requirement.

[45] AAI, p. 102.

However, given the large increase in the proposed level of capital expenditure from the present period to the next it would appear necessary to reassess the rates used.

In addition, some indirect costs are included in the payroll rates for permanent meter changes and block mains replacement work. They include pre-testing, inventory management and contractor management. These indirect costs are incorporated in the base costs (along with the contingency allowances where present) and carried into the estimates in the *Mains Replacement Plan* **before t**he application of the overhead factor we discuss here. A check should be made to confirm that overheads so added are removed from those that are applied by the percentage.

It is an accounting matter to confirm whether the proposed level of capitalisation of overheads is reasonable but if it is found not to be so there ought to be a reduction in the proposed application rates.

4.8 Other Considerations

In concluding our review of capital expenditure in the next period, we took into account Envestra's documented current practices and the Marksman reports discussed in section 3.5.

We noted the opinion from Zincara Ltd (attachment 6.6 to the AAI) in relation to its review of Envestra's operating and capital expenditure forecasts for the next period. Zincara considers that the forecast expenditure generally reflects activities and projects that would be expected of a prudent owner or operator and that the costs are efficient. Its opinion is qualified by the assumption that Envestra has corrected certain matters in its documentation that Zincara identified but these are not described.

We noted that the business had submitted comprehensive expenditure plans supported by business cases and transparent cost calculations, all of which were made available to us at the outset of our work.

We noted that the work is mostly contracted out competitively.

We received and relied on explanations given by the business in its AAI and by the management and staff of the business at the meetings held with them in October.

We took into account the circumstances in which the business expects to operate in the next period.

In essence, we sought by these methods to confirm the necessity, optimality and cost effectiveness of the capital expenditure made in the present period and, in general, we were satisfied by the information received.

As a result, we have concluded that the work foreseen is well supported, except in those cases that we have mentioned earlier in this section of the report.

4.9 Conclusion

Taking all matters reported in this section into consideration we conclude that Envestra's proposed capital expenditure in the next period is prudent and efficient, subject to the adjustments shown in Table 4.4.

The adjustments shown in relation to the contingency allowances are estimates, as cost details were available only in relation to direct costs and we were unable to determine the correct calculation.

The business should be asked to re-submit its expenditure proposal exclusive of contingency allowances and the other adjustments at the appropriate time.

No adjustment has been incorporated to reflect lower rates of application of indirect costs and overheads, although that appears necessary, as noted in section 4.7.

In all cases, capital contributions or recoveries by or from other parties need to be deducted from the gross expenditure in accordance with the applicable regulatory accounting policies.

Table 4.4: Recommended Level of Capital Expenditure in Next Period ($2010 m)

FY ->	**2012**	**2013**	**2014**	**2015**	**2016**	**Total**
Envestra's proposal	33.9	37.4	32.4	32.0	33.5	169.1
Less recommended reductions						
Reduction in mains replacement work	5.5	5.6	5.8	5.9	6.0	28.8
Removal of contingency allowances:						
Services (Inlets) (10%)	0.6	0.6	0.7	0.6	0.7	3.2
Augmentation projects (8%) b/	0.0	0.2	0.0	0.0	0.0	0.3
Sleeved railway crossings (20%)	0.1	0.1	0.1	0.1	0.1	0.6
Recommended level of capex a/	27.7	30.8	25.8	25.3	26.6	136.2

a/ Subject to the qualifications in the main text. Figures may not add due to rounding.

b/ Excluding Sandgate and reactive-recurrent work.

5 Operating Expenditure in Present Period

5.1 Summary of Expenditure

Although we are not required to assess Envestra's operating expenditure in the present period other than in terms of the reasonableness of its level in the "base year" (*viz.* FY 2010) – a matter that we discuss in section 5 of this report – we considered it necessary to review the expenditure in the present period briefly to provide the setting for our review and operating expenditure in the next period.

Operating expenditure in the present period is summarised in Table 5.1.

Table 5.1: Operating Expenditure in Present Period ($2010 m)

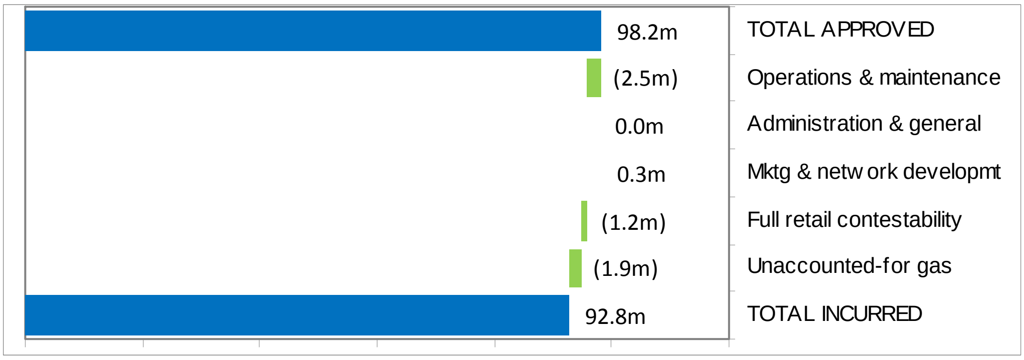
		FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	**Total**
Operating & maintenance	Approved	14.2	13.7	13.4	13.3	13.2	**67.7**
	Incurred	13.4	12.3	13.2	13.1	13.2	**65.2**
	Variance	(.8)	(1.4)	(.2)	(.2)	.1	**(2.5)**
Administration & general	Approved	2.2	2.4	2.8	2.8	2.8	**13.0**
	Incurred	2.3	1.6	2.6	3.3	3.3	**13.0**
	Variance	.0	(.8)	(.2)	.5	.5	**.0**
Network development / marketing	Approved	1.0	1.0	1.0	1.0	1.0	**5.0**
	Incurred	1.0	1.0	.9	1.2	1.2	**5.2**
	Variance	(.0)	(.0)	(.1)	.2	.2	**.3**
FRC operating costs	Approved	.1	1.8	1.4	1.4	1.4	**6.1**
	Incurred	.0	1.9	1.1	1.0	1.0	**4.9**
	Variance	(.1)	.1	(.4)	(.4)	(.4)	**(1.2)**
Unaccounted for gas	Approved	1.5	1.4	1.3	1.2	1.1	**6.4**
	Incurred	1.7	1.6	.4	.4	.5	**4.5**
	Variance	.2	.3	(.9)	(.8)	(.7)	**(1.9)**
Total	**Approved**	**19.0**	**20.2**	**19.8**	**19.7**	**19.5**	**98.2**
	Incurred	**18.3**	**18.3**	**18.1**	**18.9**	**19.2**	**92.8**
	Variance	**(.7)**	**(1.9)**	**(1.7)**	**(.7)**	**(.3)**	**(5.4)**
	Variance (%)	**-4%**	**-10%**	**-9%**	**-4%**	**-2%**	**-5%**
Total excluding network development, marketing and UAFG	Approved	16.5	17.8	17.6	17.5	17.4	**86.8**
	Incurred	15.6	15.7	16.8	17.4	17.5	**83.1**
	Variance	(.9)	(2.1)	(.7)	(.1)	.2	**(3.7)**
	Variance (%)	-5%	-12%	-4%	-1%	1%	**-4%**

Source:AAI, p. 30, Table 3.3 (incurred) and revised Table 3.4 submitted to the AER (approved).
Figures may not add due to rounding.

5.2 Variances

Envestra estimates total operating expenditure in the present period to be $98.2 m, $5.4 m (5.5%) below the $98.2 m approved for the period by the QCA. Figure 5.1 shows the variances by expenditure category, highlighting the fact that the main variances occurred in the categories of operations and maintenance, unaccounted for gas and full retail contestability (FRC) costs.

Figure 5.1: Variances between Incurred and Approved Opex ($2010 m)



Operating and Maintenance

The largest variance is in operating and maintenance expenditure. Envestra expects to spend $2.2 m (3.7%) less on this item in the present period than was approved by the QCA. The variation occurred in the first two years of the present period and expenditure is expected to be similar to the approved level during the last three years of the period.

Unaccounted-for Gas

The second largest variance in total operating expenditure is in the cost of UAFG, in relation to which Envestra expects to spend $1.9 m (30%) less in the present period than was approved. We do not comment on the price applicable to the purchase of gas to replace losses, as that is not a technical matter; and we have discussed UAFG in volumetric terms in section 4.2 of this report, noting that we do not agree with all aspects of Envestra's claim on p. 32 of its AAI in relation to movements in the level of UAFG in its Brisbane network.

Full Retail Contestability

The third largest variance is in the costs associated with the introduction of full retail contestability (FRC). Envestra expects to spend $1.2 m (5.0%) less on this item in the present period than was approved. Expenditure is expected to drop in the last three years of the present period and Envestra states that, after the initial implementation of FRC, it has been able to achieve savings by implementing similar FRC systems and achieving efficiencies across the three networks it owns. [46]

Administration and General

Administration and general costs are forecast to be similar to the approved level over the whole period. We note, however, that expenditure was below the approved level in the early part of the period but is forecast to be above it in the last two years. We further note that there was a 27% increase in expenditure between FY 2009 and FY 2010.

5.3 Conclusion

We discussed the expenditure during our meetings in Adelaide and have taken the observations noted above into account in our further reviews in the remaining sections of this report.

[46] Envestra South Australia AAI, p.34.

6 Operating Expenditure in Next Period

6.1 Summary of Proposed Expenditure

The proposed operating expenditure in the next period is $107.0 m compared with the forecast $92.8 m in the present period, an increase of 15.3%. A summary of the proposed expenditure is shown in Table 6.1.

Table 6.1: Operating Expenditure in Next Period ($2010 m)

FY ->	2012	2013	2014	2015	2016	**Total**
Operations & maintenance	13.5	13.7	14.0	14.2	14.4	**69.7**
Administration & general	3.3	3.4	3.5	3.6	3.7	**17.5**
Unaccounted for gas	1.7	1.5	1.2	0.9	0.6	**5.9**
Network development / marketing	1.7	1.7	1.7	1.7	1.8	**8.6**
FRC	1.0	1.0	1.0	1.1	1.1	**5.2**
Base opex	21.2	21.3	21.4	21.5	21.5	**106.9**
Non-base year costs	0.4	0.6	(0.4)	(0.8)	(1.3)	**(1.5)**
Incremental growth	0.1	0.2	0.3	0.5	0.6	**1.7**
Total	**21.6**	**22.1**	**21.4**	**21.1**	**20.8**	**107.0**

Sources: AAI, p. 73, Table 6.1 and RIN. Figures may not add due to rounding.

Basis of the Proposed Expenditure

For the categories of "operating and maintenance", "administration and general" and FRC Envestra has used the "base-year roll-forward approach".[47] The base year used is FY 2010 (with 9 months actual and 3 months forecast). For the categories of UAFG and network development and marketing, Envestra states that because the base year is not representative of the future, they have made forecasts year-by-year. [48]

Growth

The AAI states that the cost drivers of the business at a departmental level have been examined with the conclusion that, in the short-term, the bulk of operating expenditure is fixed, i.e., it does not vary with incremental usage or throughput. [49] The exceptions are costs that vary with incremental network expansion and number of customers (e.g., meter reading, maintenance, etc). Envestra has applied an additional cost per customer to adjust those components to account for growth, as we discuss later in this section of the report.

Real Cost Escalation

Envestra has applied escalators to its operating expenditure forecasts to reflect expected increases in its costs in real terms. Their application is set out in the attachment 6.7 to the AAI (*Opex Forecast - September 2010*).

47 A level of operating expenditure in the next period that is based on the level in a base year, with non-recurrent items removed, step changes added and escalation applied for operating and maintenance growth (using a proxy for it), forecast real changes in input costs – *viz.* materials, labour, overheads and escalation.

48 AAI, p. 73.

49 AAI, p. 84.

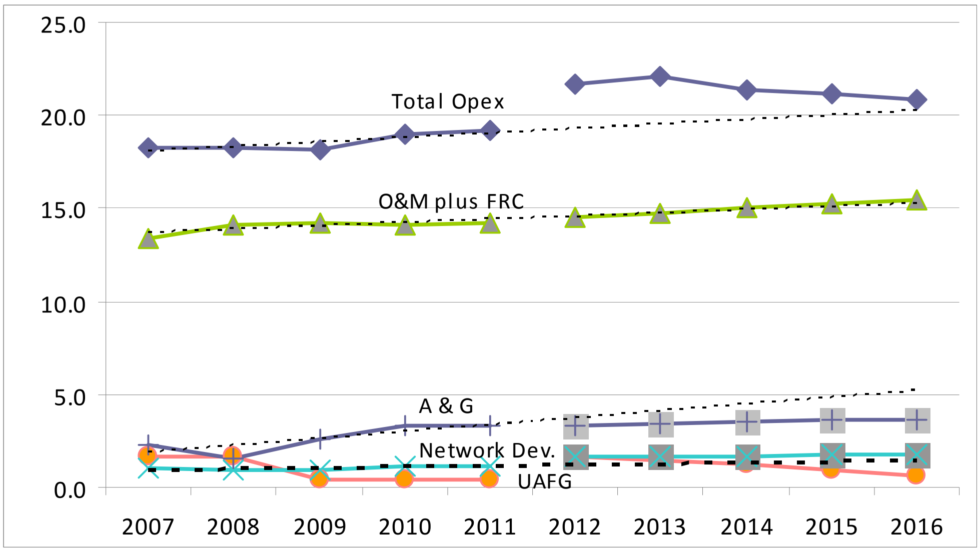
Envestra states in its AAI (p. 84 *et seq*) that real cost escalators for the next period were provided to it by its consultant, BIS Shrapnel; that each forecast item has been split as general labour, electricity-gas-and-water labour, network materials (mainly polyethylene piping), general materials and, in relation to capital expenditure, contract labour for the construction sector. Forecast costs have been split into these categories in accordance with an average of historical expenditure. The escalators are applied in each year of the next period.

We note that the escalators have been derived independently and generally accord with our understanding of cost movements in the gas sector. However, we have not assessed their quantum, only their method of application as outlined below.

Movements from Present Level

Figure 6.1 shows the trend of total operating expenditure by category over the present period and the next period as proposed by Envestra.

Figure 6.1: Expenditure Category Trend ($2010 m)



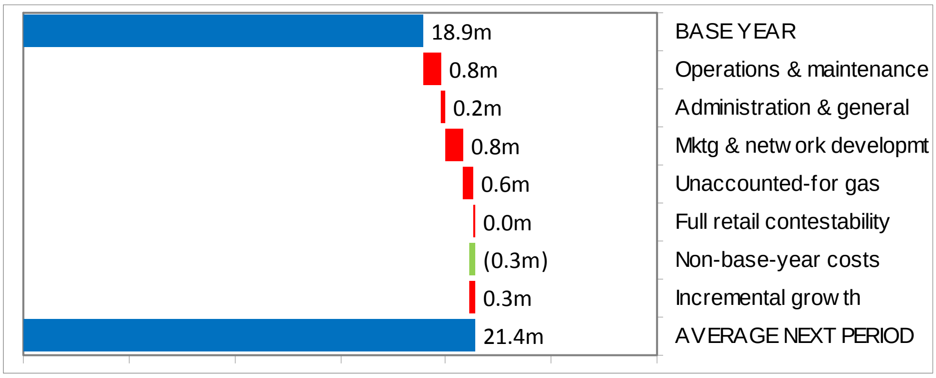
The chart shows that total expenditure is forecast to increase above the trend line at the start of the next period, then decline over the rest of the period. The change at the start of the period results from forecast increases in UAFG and the non-base-year costs added to the base-year level.

Total operating expenditure in the first year of the next period is $21.6 m, an increase of $2.7 m (14%) above the base-year total. Average annual operating expenditure for the next period is $21.4 m compared with the base-year total of $18.9 m, an increase of 13%.

Figure 6.2 shows the contribution of changes in the various expenditure categories to the change between the base-year level and the average level for the next period.

UAFG, marketing and network development costs and operations and maintenance costs each account for approximately a third of the total increase over the period. The increases in operating and maintenance and administration and general costs are caused by real cost escalation as any step changes in these costs are included in non-base-year costs.

Figure 6.2: Increases from Base-Year to Next Period ($2010 m)



6.2 Expenditure Level in Base Year

Proposed Base-Year Costs

Envestra has used base-year figures to project only operating and maintenance and administration and general expenditure in the next period with the other categories, UAFG and network development, being calculated year-by-year. Expenditure in the applicable categories in the base year and the three preceding years is shown in Table 6.2. The table illustrates that expenditure in the base year for operating and maintenance is consistent with earlier years, FRC is consistent with the previous year, but there is some variability in administration and general with an apparent increase in the base year. Total expenditure over the three categories in the base year is similar to the allowance.

Table 6.2: Base Year Selection ($ FY 2010 m)

FY>	2007	2008	2009	**2010**
Operations & maintenance	13.4	12.3	13.2	**13.1**
Administration & general	2.3	1.6	2.6	**3.3**
FRC	0.0	1.9	1.1	**1.0**
	15.6	15.7	16.8	**17.4**
Approved Level	16.5	17.8	17.6	**17.5**

Source: AAI, p. 30, Table 3.3 (incurred), revised Table 3.4 submitted to the AER (approved). Figures may not add due to rounding.

Envestra has not identified any non-recurrent expenditure that should be removed from the base year.

We consider that FY 2010 reasonably represents the business's present costs in the expenditure categories to which the roll-forward methodology has been applied but we note a degree of volatility in the administration and general category.

Efficiency of Base-Year Costs

The AER's Criterion

The AER advises us that the test it is required to apply for the recovery of operating expenditure by a gas distributor is set out in Rule 91(1) as follows:

> Operating expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.

In chapter 5 of its AAI, Envestra sets out its claim that it is operating efficiently. We examine each of its supporting arguments in the following sections.

Outsourcing Arrangement

Since its inception, Envestra has outsourced the operation and management of its gas distribution businesses to a third party. The motivation for this is "to ensure Envestra would continue … as a low cost operator by accessing the economies of a larger organisation."[50]

The ownership and structure of the party providing these operating services has changed several times over the last ten years and the party now providing the outsourced services is the APA Group. [51] The Group holds 30.6% of Envestra's ordinary capital and hence is a related party. However, Envestra has provided an extensive explanation of the outsourcings and arguments that support the proposition that the contract should be considered an arm's length commercial arrangement.

The amount payable by Envestra under the operating and management agreement is the sum of: [52]

(a) all costs and disbursements reasonably incurred or outlaid by the APA Group in the performance of its obligations under the agreement;
(b) a network management fee, being 3% of network revenue;
(c) incentive payments in respect of a completed financial year for real reductions in the average capital cost of connecting new consumer sites and controllable costs per gigajoule of gas. The incentive payments are equal to one third of the reduction in costs from the immediately preceding financial year, after these costs have been adjusted for inflation; and
(d) costs and expenses incurred by the APA Group consequent upon employees being made redundant

The AAI states that Envestra receives the benefits of the economies of scale in purchasing achieved by the APA Group, which manages several other major network businesses.

Envestra commissioned a report by KPMG to estimate the costs that would be likely to be incurred if Envestra itself managed the Queensland and South Australia networks. [53] It concluded that the payments to the APA Group are lower than the costs that would be incurred if Envestra managed its assets directly.

Another report was commissioned from NERA Economic Consulting to evaluate the asset management fee, including incentives, payable to the APA Group. [54] It is a well researched and convincing study that concluded that the revenue asset management charge levied on Envestra by the APA Group resulted in a gross margin not out of line with those earned by comparable, mainly asset management, businesses.

We noted that the management fee payable to the APA Group is based on a percentage of Envestra's revenue, plus incentives for certain activities, and that the fee is not built into the Group's charges to Envestra.

Overall, we were satisfied that the outsourcing arrangement provides Envestra with economies of scale that it would not be able to access on its own. Only those costs actually

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50 AAI, pp. 49-50.

51 AAI, p 38.

52 AAI, p. 56.

53 AAI, attachment 5.6.

54 AAI, attachment 5.9.

incurred are passed through to Envestra, meaning that they are transparent; and incentives are in place to minimise them. Independent reviews (by KPMG on managing the business in-house and by NERA on the appraisal of contractor profit margins) have concluded that the arrangement results in costs lower than Envestra would incur if it operated the network itself and that the management fee charged is not out of line with margins expected from asset management businesses.

(It is a matter for the future, as it is the base-year level of expenditure that we discuss here, but the prudence and efficiency of the costs incurred over time will be determined ultimately by how well the contractor performs.)

Total Factor Productivity Report

Envestra engaged Economic Insights to examine the total factor productivity (TFP) and partial factor productivity (PFP) of Envestra's South Australian and Queensland networks. Its report examined the TFP and PFP growth of Envestra's South Australia and Queensland gas distribution businesses and those of the three Victorian gas distribution businesses (GDBs) – Envestra Victoria, Multinet and SP AusNet and, in New South Wales, Jemena Gas Networks (JGN). [55]

The TFP measure used included three outputs (throughput, customer numbers and system capacity) and eight inputs (operating expenditure, lengths of transmission pipelines, high pressure pipelines, medium pressure pipelines, low pressure pipelines and services, meters, and other capital). For productivity level comparisons, transmission pipelines and associated operating expenditure were excluded.

The report concluded, "Envestra Queensland's changes in output and input quantities have led to a variable productivity performance over the last 12 years. Its partial productivity of opex increased between 1999 and 2002 but has fluctuated since then producing an annual growth rate of around 1% over the last 12 years. Annual growth in the partial productivity of capital, on the other hand, has been – 1.1% over the last 12 years." [56]

It further concluded, "Envestra Queensland's TFP index exhibited a trend decline over the past 12 years given the higher weighting given to capital relative to opex. The average annual growth rate was – 0.2% for the period 1999 to 2010 although it was – 0.6% for the last 6 years."

"While Envestra Queensland's TFP growth matched those of JGN and Envestra SA and exceeded that of the Victorian industry between 1999 and 2002, Envestra Queensland's TFP has generally declined since 2002 whereas TFP for Envestra SA, JGN and the Victorian industry continued to increase after that."

Finally, the report concluded, "Being a small GDB operating in a subtropical climate Envestra Queensland would be likely to be at a significant disadvantage relative to the other included GDBs in comparisons of productivity levels as it is by far the smallest, has low overall energy density, and by far the lowest domestic energy density and customer density. In 2006 Envestra Queensland achieved 76% the TFP level of Envestra SA, 70% that of JGN and between 60% and 70% of those of the three Victorian GDBs. However, its operating environment conditions are so different to those of the other included GDBs that it is difficult to establish whether Envestra Queensland is operating efficiently based on this comparison. To do this we would need to either include other small GDBs operating in a subtropical environment or undertake econometric adjustments for operating environment conditions.

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[55] AAI, attachment 5.7.

[56] AAI, attachment 5.7 p. 38.

The number of observations available in the Economic Insights GDB database precludes the latter option."[57]

Whilst total and partial factor productivity concepts may be considered esoteric, they have been applied fairly consistently to gas and electricity utilities in Australia and New Zealand for over ten years by several parties. The methodology uses operating expenditure as one of the inputs but capital is represented by surrogates: pipeline lengths, meters and the value of other assets.

The conclusions indicate that the productivity of Envestra's Queensland network operation has been deteriorating and does not compare favourably with the other networks considered, although the report notes the Queensland network is small by comparison to the others and has lower customer and energy densities. Whilst the network is small, we note that Envestra claims that its outsourcing arrangement with the APA Group provides economies of scale that offset the disadvantages of having a smaller network. It should also enjoy small, further, benefits from owning and operating three gas networks.

Benchmarking Report

Envestra engaged Marksman Consulting to benchmark the cost performance of Envestra's South Australian and Queensland businesses against several large Australian gas distribution businesses. .

Its report presents a range of operating and capital expenditure performance indicators for nine gas distribution businesses between 2002 and 2010.[58] The operating expenditure measures excluded the costs of UAFG as they are not reported in Victoria and full retail contestability costs are excluded from the distributors in Queensland as the QCA approved a pass-through arrangement for them. [59]

Generally, the use of benchmarking is more valid for operating expenditure than capital expenditure as capital expenditure is significantly influenced by growth and expansion rates and the age of existing network assets. Benchmarking is also more useful when the characteristics of networks and the conditions under which they operate are similar or can be normalised. Gas networks tend to have a much wider range of energy and customer densities than electricity networks with the result that the information presented from benchmarking needs to be carefully interpreted and, at best, will present only a broad indication of cost performance. It is important to identify network characteristics that may result in dissimilar cost structures that suggest that a further detailed "bottom-up" analysis of costs should be undertaken.

The Marksman report concludes with respect to Envestra's Queensland network that "It is difficult to draw meaningful conclusions in regard to the efficiencies of Envestra Queensland's historical Capex and Opex, as Envestra Queensland's operating conditions are so different. The most comparable gas business is APT Allgas, and for some measures, Envestra compares favourably with APT Allgas; but for other measures, it is the other way round or they are much the same. Marksman concludes that Envestra Queensland's Capex and Opex have historically been commensurate with that of APT Allgas." [60]

We do not agree in respect of operating expenditure that the conclusions of the Marksman Consulting Report are valid. The analysis they undertook clearly shows that Envestra

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[57] AAI, attachment 5.7 pp. 38-39.

[58] AAI, attachment 5.8. Data were not presented for all businesses over the whole period.

[59] This will result in operating expenditure for the Queensland distributors being understated.

[60] AAI, attachment 5.8 p. 16.

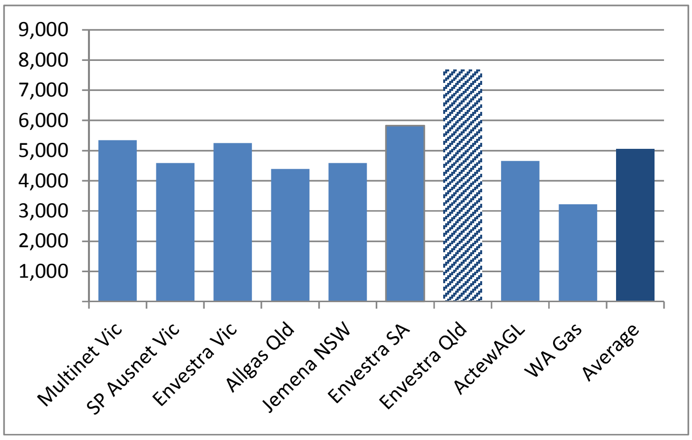
Queensland, particularly since 2006, has higher operating costs than the other companies including APT Allgas. [61]

Our Assessment

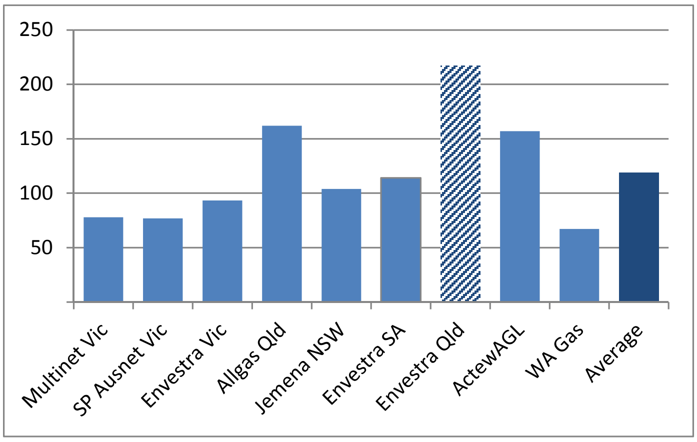
We took the **data** in the Marksman report and analysed them for FY 2009, the most recent year for which data from all distributors are available and a year close to the year chosen by Envestra as its base year. We also calculated simple averages for the indicators over the nine distributors. Figure 6.3 shows the operating expenditure performance on a cost per km and cost per customer basis for FY 2009.

Figure 6.3: Opex Performance Indicators in FY 2009

Opex /km



Opex/Customer



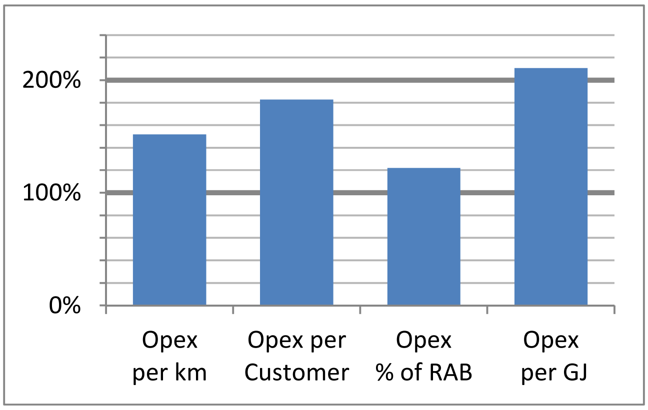
The analysis shows that in FY 2009 Envestra's Queensland network had both the highest operating expenditure per kilometre and per customer of the businesses compared.

We also calculated the relative performance of the business using the same **indicators** as those in the Marksman Report by calculating the Envestra's Queensland performance as a percentage of the average cost of all the businesses compared and the results are shown in Figure 6.4. The analysis shows that Envestra's Queensland business is above the mean on all measures by between 20% and 105%.

[61] Prior to 2006, APT Allgas did have higher operating cost measures but this has changed materially since that time.

Envestra's Queensland operation is small, with low customer and energy density. However, it operates in a similar geographical environment and is of a similar size to APT Allgas' operation in Queensland yet, in spite of this, Envestra's operating cost per km is still 75% higher than APT Allgas' and its operating cost per customer is 34% higher.

Figure 6.4: Relative Opex Performance in FY 2009



We considered whether other characteristics (such as the amount of unprotected steel and cast iron mains in service) might account for the difference but have were not able to identify any impact.

In short, the difference from industry norms indicated by our analysis suggests that operating costs on Envestra's Queensland network may not be at an efficient level.

Further Considerations

Data provided by Envestra in relation to the cost of adding new customers to its networks show that the unit cost in its Queensland business is twice that in its South Australian business. We consider that this provides a further indication that its costs are above an efficient level in Queensland.

A requirement when assessing the efficiency of base-year costs is that they reflect the condition of Envestra's network in the year concerned. The point is particularly relevant, given the presence of significant lengths of mains said by Envestra to be in a deteriorated condition (although doubt is cast on that claim when recognition is given to the very low level of UAFG actually metered). Any impact attributable to this consideration appears to be offset by the fact that APT Allgas and Envestra's South Australian networks exhibit similar percentages. Thus, the length of mains said to be in a deteriorated condition does not appear to be a material factor its higher operating costs.

Conclusion on Base-Year Level of Expenditure

Summarising these matters, we note the following.

(a) Total operating expenditure in the present period is forecast to be below that approved by the QCA in the last determination. [62]

(b) Comparison of the expenditure in the base year with that in the preceding years and that approved by the QCA indicates that the selected year reasonably represents the business's present costs in the expenditure categories for which the roll-forward

[62] These categories now include FRC costs that have been included in the operating and maintenance category for the next period.

methodology has been applied (although we note a degree of volatility in administration and general expenditure).

(c) Envestra has not made any adjustments for non-recurrent costs in the base year.

(d) We found no evidence that Envestra incurs additional costs as a direct result of the operating and management agreement with the APA Group. On the contrary, the information provided by Envestra indicates that costs are lower than would be incurred if it undertook the work itself. The report commissioned from NERA supports that view. [63]

(e) The productivity report prepared by Economic Insights concludes that Envestra's productivity has declined over recent years and that its productivity performance is inferior to that of other gas distribution businesses, even if the comparative businesses are larger in most cases and have higher customer and energy densities.

(f) Our analysis of the benchmarking data for FY 2009 – the most recent year for which data from all companies was provided in the report from Marksman Consulting for Envestra – indicates that Envestra's operating costs are materially higher than other distributors and we have not been able to identify reasons why this should be so.

(g) Unit rates used for calculating the cost of adding new customers to the network are double those that Envestra incurs in South Australia.

Taking these considerations together, we conclude that Envestra has **not** demonstrated that its base-year expenditure is efficient.

A detailed study of Envestra's operation would be required to identify the reasons for its present cost structure. It would require data and entail observation at a very detailed level beyond the scope of this review.

Nonetheless, we consider that an adjustment is required in Envestra's approved operating expenditure for the next period to bring it to an efficient level.

For practical purposes from the business's standpoint, we consider it would be more reasonable to apply the correction as an annual compounding productivity improvement adjustment to apply to the base-year level throughout the next period than to propose a sudden change. Therefore, we recommend an adjustment of 2.5% p.a., applied to expenditure **excluding** UAFG and other non-base-year costs, compounding from the level of expenditure in the base year (FY 2010).

By the end of the next period, the total reduction will be 16%.

We consider this a conservative but realistic approach, based on the information available.

In recommending this adjustment, we confirm that we have taken into account the reduction that Envestra proposed in its operating expenses because of its mains replacement programme, as adjusted by us in this section of the report. By the end of the next period this reduction (as adjusted by us) will amount to an additional 7% reduction in total operating expenditure excluding UAFG and other non-base year costs.

We note that if the combined 23% reduction were to be applied to the business's costs in our benchmarking analysis in Figure 6.3, the business would still have the highest cost per customer and per kilometre but be notably closer to the mean.

The application of the recommended, compounding 2.5% annual adjustment to operating and maintenance expenditure, administration and general expenditure and FRC costs (the

[63] The outsourcing arrangement has the potential to deliver efficiencies of scale. However, as already noted, we have not reviewed the agreement in full.

categories to which the "base-year roll-forward" methodology is applied), is shown in Table 6.3.

Table 6.3: Application of Recommended Efficiency Adjustment ($ FY 2010 m)

YE 30 June	2012	2013	2014	2015	2016	**Total**
Pct adjustment	5.1%	7.7%	10.4%	13.1%	16.0%	
Operations & maintenance	0.7	1.1	1.4	1.9	2.3	**7.3**
Administration & general	0.2	0.3	0.4	0.5	0.6	**1.9**
FRC	0.1	0.1	0.1	0.1	0.2	**0.5**
Total Escalated	**0.9**	**1.4**	**1.9**	**2.5**	**3.1**	**9.7**

6.3 Operating and Maintenance Costs

The "base-year roll-forward" methodology has been used to project operating and maintenance costs in the next period. They are expected to rise from the base year at a rate between 1.0% and 2.0% p.a. Since all step and scope changes and growth impacts are listed in separate categories, these increases are due only to real price escalation.

Envestra has applied escalation to these costs based on an allocation of 85% to gas network related labour and 15% to network materials. [64] Maintenance costs are typically labour dominated so we consider that this is appropriate.

We conclude that the method of application of escalation is appropriate but, as noted in section 6.2, we consider that Envestra has not demonstrated that its base-year expenditure is efficient and an efficiency adjustment totalling $7.3 m is recommended over the period as shown in Table 6.3. [65]

6.4 Administration and General Costs

Envestra has used the "base-year roll-forward" methodology to forecast administration and general costs in the next period. These costs increase from the base year at a rate between 0.6% and 2.9% p.a. Since all step and scope changes and growth impacts are listed in separate categories these increases are due only to real price escalation.

Envestra has applied escalation to these costs based on an allocation of 85% to general labour and 15% to general materials. The costs are typically labour dominated through direct labour or contracted services so we consider that this split is appropriate.

We conclude that the method of application of escalation is appropriate but, as noted in section 6.2, we consider that Envestra has not demonstrated that its base-year expenditure is efficient and an efficiency adjustment totalling $1.9 m is recommended over the period as shown in Table 6.3. [66]

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[64] AAI, attachment 6.7 *Opex Forecast (September 2010)*.

[65] For clarification, we are not expressing an opinion on the rates of escalation proposed, only on the application of the rates to the type of expenditure involved.

[66] See footnote 65.

6.5 FRC Costs

The "base-year roll-forward" methodology has been used to forecast FRC costs in the next period. They are forecast to rise from the base year at a rate between 1.0% and 1.9% p.a. Since all step and scope changes and growth impacts are listed in separate categories, these increases are due only to real price escalation.

Envestra has applied escalation to these costs based on an allocation of 66% to gas network related labour and 34% to network materials. [67] FRC costs are typically labour and IT-related expenditure so we consider that this is appropriate.

We conclude that the method of application of escalation is appropriate but, as noted in section 6.2, we consider that Envestra has not demonstrated that its base-year expenditure is efficient and an efficiency adjustment totally $0.5 m is recommended over the period as shown in Table 6.3. [68]

6.6 Marketing and Network Development Costs

Marketing and network development comprises those activities undertaken to increase the number of customers and their average consumption and to facilitate expansion of the network. These activities are designed to position and promote natural gas against alternative fuels, principally by advertising and by payment of incentives to connect gas appliances. They include operational and engineering activities required to process connection orders without which Envestra would be unable to connect customers to its network.

Approximately 50% of the expenditure in this category relates to the labour involved in planning new connections. We note that this expenditure is consistent with that incurred in the present period with real cost escalation applied and we consider this component of the expenditure prudent and efficient. [69]

The remaining expenditure is the marketing component of this cost (and the portion of network development costs related to the provision of subsidies to customers). This is not a technical matter and so we do comment further on it other than to note that the expenditure may be an important ingredient in achieving the projected rate of growth in gas sales that underpins the expenditure estimates.

6.7 Unaccounted-for Gas

Gas Volume

We discussed UAFG and various considerations related to it in section 4.2 of this report, noting that Envestra's metering systems reported a level of UAFG in the network in FY 2010 of only 0.6%.

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67 AAI, attachment 6.7 *Opex Forecast (September 2010)*.

68 See footnote 65.

69 We noted from the operating expenditure model that Envestra has applied escalation to network development costs in the ratio of 51% electrical-and-gas-worker labour and 49% general materials (*Network Development Plan*, p. 26). This appears to be a high allocation to labour, given that 88% of the expenditure is proposed to be on market development programmes (principally, advertising and incentives) and only 12% on operational support. We consider a more appropriate ratio would be 12% to electrical-and-gas-worker labour and 88% to general materials. Applying that ratio would reduce the proposed cost by $0.23 m over the next period. We have not recommended an adjustment in this respect as the amount is not material.

We note again that if there are losses on the network in excess of the measured level, then either the gas suppliers or Envestra's gas consumers are paying for them already, avoiding the need for a further allowance for UAFG to be included in the proposed expenditure.

We therefore find no reason to recommend a level of UAFG in the next period that is greater than the level that the business presently measures, *viz.* 0.6% of gas input for its networks as a whole as measured in FY 2010 – or, expressed more correctly in quantitative terms, UAFG of 92.3 TJ p.a.

Gas Price

We do not comment on the price of gas purchased to replace losses as that is not a technical matter.

6.8 Evaluation of Step Changes and Other Cost Changes

Envestra has factored several "step changes" and other cost changes into its forecast level of operating expenditure, claiming that they are not reflected in its present costs or in its base-year level of expenditure. It refers to them as "non-base-year" costs and classifies them under the following headings that we deal with in turn in the next section of the report:

- cost increases arising from capital works,
- cost increases related to *ad hoc* projects, and
- operating expenditure step changes.

The net effect of the changes is to reduce expenditure by $1.5 m over the period, as summarised in Table 6.4. Individual projects have been calculated on FY 2010 costs with real cost escalation added to the total.

Table 6.4: Non-Base-Year Costs ($2010 m)

YE 30 June	2012	2013	2014	2015	2016	**Total**
Opex related to capex	(0.0)	(0.3)	(0.7)	(1.1)	(1.5)	**(3.6)**
Ad hoc projects	0.3	0.6	0.0	0.0	0.0	**0.8**
Step changes	0.1	0.3	0.3	0.3	0.4	**1.5**
Total Unescalated	0.3	0.6	(0.4)	(0.7)	(1.1)	**(1.3)**
Total Escalated	**0.4**	**0.6**	**(0.4)**	**(0.8)**	**(1.3)**	**(1.5)**

Source: AAI, attachment 6.8 *(Opex Non Base year Costs - September 2010).*

The effect of cost increases summarised in the table is to reduce operating expenditure in the next period by 1.4%.

The changes are outlined on pages 79-84 of Envestra's AAI and in more detail in the business cases that accompany the AAI.

However, before proceeding to assess these items, we first set out our method of evaluation.

Introduction

In regulatory price reviews, operating expenditure forecasts prepared by a business are typically based on operating expenditure levels in the previous period (often in a particular base year) with specific cost changes identified as "step changes" or other cost changes. These are usually additional costs but may be reductions.

Before proceeding to our evaluation of Envestra's costs, we set out below the general considerations in relation to our review of such costs and the criteria we have applied when determining whether such "step changes" or other cost changes are prudent and efficient.

No Implied Interpretation of the Rules

In setting out these considerations and criteria, our purpose is solely to base our assessment on the prudence and efficiency of the proposed expenditure as is required by our terms of reference. We do not attempt to interpret the Rules, as we do not consider it our place to do so.

General Considerations

In a competitive market, businesses normally seek to minimise their own costs and do not add to them or pass them on to customers unless they are satisfied that there is a benefit to customers in terms of the product delivered, that a price increase will not jeopardise sales or the viability of the business, that a benefit will accrue to the business in terms of efficiency or, ideally, all of these things. Regulation presumably ought to incentivise natural monopolies in a similar way. Second, businesses are dynamic, with variations occurring from year to year. Such variations ought not to form the basis of a claim for a "step change", as the effect of that would be to allow costs to be passed on readily in contravention of the efficiency objective implicit in the regulatory framework.

We consider that a methodology that starts with a base year and then applies cost escalators, workload escalators, "step changes" and other cost changes may lead to a projection of future costs that is above an efficient level unless there is also explicit consideration of (and, where appropriate, allowance in the projections for) business efficiency improvements.

An experienced consultant reviewing such expenditure would normally be mindful of the following considerations:

- (a) whether a demonstrated need for expenditure has been identified in the business's submissions and supporting documentation;
- (b) whether it is matched to new or altered regulatory obligations (e.g., to technical standards, safety standards, performance or security-of-supply requirements or other statutory or licence obligations);
- (c) whether it aligns with the business's broad policies regarding, for example, maintenance practice, risk assessment and management or the like that have a material impact on operating expenditure;
- (d) whether benefits, quantifiable or not, have been identified in the documentation;
- (e) whether, if quantifiable, the benefits were so quantified in terms of amount and time of occurrence or at least likely time of occurrence;
- (f) whether, if quantified, evidence has been presented sufficient to demonstrate that the solutions chosen were based on comparative studies and were demonstrated to be the least-cost options for meeting the need;
- (g) whether, if the identified benefits had been said to be in the form of improvements in service levels, reliability or the like, they are reflected in projected improvements in the corresponding service targets;
- (h) whether a time lag in the appearance of benefits ought to be recognised in particular cases and, if so, to what extent; and
- (i) whether there are any other relevant factors to be considered.

Criteria Applied

The criteria that we have applied when considering the prudence and efficiency of "step changes" and other cost increases are set out below. They are for application in parallel with the demonstration by the business: (a) that it has adjusted its base-year expenditure to remove items that were abnormal or will clearly not recur and to add items that would normally be present; and (b) that the "step changes" and other cost increases do not duplicate any allowances for workload escalation or inflation in the next period that have been applied separately.

For a "step change" that results in an increase in costs (or any other cost increase) to be considered prudent and efficient, the business should have demonstrated that:

(a) it is related to a fundamental change in the business environment arising from external factors; or

(b) it is attributable to the imposition of new or changed obligations due to external factors including, if relevant, mandated improvements in service levels or safety; or

(c) it is of a type that will improve (as opposed to maintain) service levels voluntarily, as opposed to their improvement being mandated – in respect of which customers' willingness to pay for the improved service should be demonstrated (an extension of the first and second criteria); or

(d) it will bring cost savings or benefits in respect of which the business should be able to demonstrate that: (i) it is continually looking for better ways of using its resources and improving its processes and systems to improve service levels or achieve cost efficiencies; (ii) it has defined the savings and benefits in terms of their nature and the expected time if their realisation; and (iii) where the savings and benefits are quantifiable, they have been quantified in sufficient detail for cost-benefit analyses to be prepared and that the cost-benefit analyses justify the investment; or

(e) it is a material, additional expenditure that will enhance asset performance or mitigate identified risks associated with an existing activity and is consistent with the actions of a prudent operator in this respect.

Where it is claimed by the business that the "step changes" or other cost increases are justified by benefits that will accrue later, it should have been demonstrated by the business that the delay in the benefit stream would not be sufficient to render the additional costs unjustified.

Alternatively, if the costs do not meet any of these criteria, the business should have demonstrated that it would continue to operate efficiently as a whole, despite the cost increase.

6.9 Assessment of Step Changes and Other Cost Changes

In this section, we assess Envestra's step changes and other increases in operating expenditure under the categories it assigned: (a) cost increases arising from capital works, (b) cost increases related to *ad hoc* projects, and (c) operating expenditure step changes. In subsection (d) at the end, we consider other identified matters that lead to increases in the proposed operating expenditure in the next period.

(a) Cost Increases Arising from Capital Works

Envestra has proposed three capital expenditure projects that lead to increases in the base-year level of operating expenditure. These are shown in Table 6.5.

Table 6.5: Cost Increases Arising from Capital Works ($2010 m un-escalated)

YE 30 June	2012	2013	2014	2015	2016	**Total**
IT		0.15	0.15	0.17	0.17	**0.63**
"Fringe point" pressure monitoring	0.00	0.00	0.00	0.01	0.01	**0.02**
Leak repair cost saving	(0.03)	(0.42)	(0.84)	(1.27)	(1.71)	**(4.27)**
	(0.03)	**(0.26)**	**(0.69)**	**(1.10)**	**(1.54)**	**(3.62)**

Source: AAI, attachment 6.8 *(Opex Non Base Year Costs - September 2010).*

IT expenditure (Business Case Q22) is associated with the planned "roadmap initiative" capital expenditure projects. The expenditure ($0.6 m for field data capture and $0.03 m for advanced asset management) includes licence fees, maintenance costs and one additional full-time-equivalent employee for data capture. We note that some allowance for offsetting efficiencies has been allowed in the advanced asset management expenditure but, although efficiency improvements are claimed as a benefit for the combined projects, no other efficiency improvements have been quantified. For that reason, we consider the proposed expenditure not efficient. As noted earlier in our criteria for assessing additional costs, benefits should be quantified and offset against costs to ensure that a net benefit exists and that a strong commercial incentive exists to undertake projects of this nature and achieve the claimed business efficiencies. We recommend that this item be removed from the proposed expenditure.

The pressure-monitoring item (Business Case Q17) involves the cost of future maintenance of new equipment to install an additional 20 pressure-monitoring data loggers. The costs have been estimated in accordance with established schedules for similar assets and amount to $.02 m over the period. We consider the project meets the criterion of improving asset performance and consider it prudent and efficient.

Savings in the cost of leak repairs (Business Case Q60) accompany the proposed mains replacement programme and are significant ($4.3 m). [70] Total leak repairs are expected to decline from the present level of 1,200 p.a. to approximately 250 p.a. by the end of the period. We reviewed the basis of the calculation and considered it reasonable. However, as discussed in section 4.2, we have recommended a smaller mains replacement programme than that proposed by Envestra and have made a consequential reduction in the savings in leak repairs of 8.5%.

(b) Cost Increases Related to Ad Hoc Projects

Envestra has proposed two *ad hoc* projects in the next period as shown in Table 6.6. The expenditure is not expected to continue indefinitely.

Table 6.6: Cost Increases Arising from Ad Hoc Projects ($2010 m un-escalated)

YE 30 June	2012	2013	2014	2015	2016	**Total**
Brisbane river crossing inspection	0.20	0.57	0.00	0.00	0.00	**0.77**
Nil gas consumption	0.05	0.01	0.01	0.01	0.01	**0.08**
	0.25	**0.57**	**0.01**	**0.01**	**0.01**	**0.85**

Source: AAI, attachment 6.8 *(Opex Non Base Year Costs - September 2010).*

[70] Savings arising from the reduction of UAFG are recognised separately.

Envestra plans to conduct an integrity assessment (by in-line inspection) of the Brisbane River crossing pipeline required for the successful completion of a “Maximum Allowable Operating Pressure” (MAOP) review in accordance with Australian Standard AS 2885.3 *Pipelines – Gas and Liquid Petroleum* (Business case Q49). This standard requires the pipeline MAOP and risk assessment to be reviewed every five years, including an inspection of the integrity of the pipeline. The pipeline has a MAOP of 4,200 kPa and is 1.8 km in length but approximately 300 metres of it is under the Brisbane River and therefore inaccessible, requiring internal inspection. We note that the cost estimate is presently only a high-level estimate, based on previous work undertaken by the APA Group. We consider that this work is prudent, as it is required to comply with the relevant standard (an external obligation), and that the estimate is likely to be reasonable.

Envestra has identified 1,600 meters that register no consumption. This could be due to a dwelling not being occupied, a non-functioning meter or some other anomaly. A programme is proposed to attend, maintain and make safe properties identified as having nil gas consumption over a 12-month period, based on analysis of meter readings (Business Case Q38). A small provision has been made to make such checks annually for any newly emerging instances. We consider the programme prudent. However, we do not consider the expenditure efficient, as no allowance has been made for the increased revenue or reduced UAFG that will result from finding and replacing faulty meters. Experience of such programmes is that costs are typically more than offset by savings. We therefore recommend that that no additional allowance is made for the costs of the programme.

(c) Operating Expenditure Step Changes

Envestra has identified ten step changes in operating expenditure to apply in the next period, as shown in Table 6.7.

Table 6.7: Cost Increases Arising from Step Changes ($2010 m un-escalated)

YE 30 June	2012	2013	2014	2015	2016	**Total**
Gas market administration	0.06	0.06	0.06	0.06	0.06	**0.30**
Meter change notification	0.04	0.04	0.04	0.04	0.04	**0.20**
Knowledge management	0.00	0.15	0.15	0.15	0.15	**0.58**
Real increase in insurance	0.02	0.05	0.07	0.10	0.14	**0.39**
	0.12	**0.30**	**0.32**	**0.35**	**0.39**	**1.47**

Source: AAI, attachment 6.8 *(Opex Non Base Year Costs - September 2010).*

Gas Market Administration

The item titled “gas market administration” (Business Case Q20) stems from the short-term trading market for gas established in late 2010. It requires Envestra to place greater emphasis on the quality and reliability of the metering data it gives to the market daily. An additional person at a senior level has been employed to support this activity, covering both South Australia and Queensland. The cost of $60,000 p.a. is half the cost of that additional person. This meets the criterion of being a new obligation on Envestra and we consider the response prudent and efficient.

Notification of Planned Meter Changes

Envestra undertakes periodic testing and replacement of gas meters (Business Case Q39). Presently, to optimise the use of resources, changing gas meters is not scheduled as planned work but as “fill-in” work. However, some consumers have complained about the resulting lack of notification of the work and Envestra plans to give advance notification of interruptions for this type of work in future. In addition to the cost of arranging notification, the increased service level is expected to result in a loss of productivity in the operations part of the business. The cost is made up of labour, materials and a 2% loss of productivity in carrying out the work. We consider that the activity is prudent as it provides an improvement in service levels and about which customers have complained. We have reviewed the cost estimate and consider the direct costs to send notices reasonable. However, we note a 0.5 FTE administration person is proposed to handle 2,465 notifications p.a. whereas in South Australia Envestra proposes one FTE to handle an average of 30,000 meter changes notifications p.a. This suggests that a lower level of administration resource than proposed is practical and we recommend allowing only 0.1 FTE, being directly proportional to the South Australian proposal. We also consider that much of the productivity loss could be avoided by good planning and by providing a notification "window" to customers to allow some flexibility about when the work can be done. We therefore do not consider the costs efficient and recommend that only the allowance to cover the direct costs and 0.1 FTE administration be approved. [71]

Knowledge Management

Envestra intends to develop a more formal process to manage its documentation (Business Case Q45). Around $0.4 m of the $0.6 m estimated cost is attributable to labour. We consider the work prudent, as it is good practice to document work processes properly. It is normal for projects of this nature to result in significant business efficiency improvements and this is given as one of the benefits of the proposed project. However, we do not consider the expenditure efficient as no allowance has been made for such efficiency improvements. As noted earlier in our criteria for assessing step changes, benefits should be quantified and offset against costs to ensure that a net benefit exists and that a strong commercial incentive exists to undertake projects of this nature and achieve the claimed business efficiencies. We recommend that this expenditure be removed from that proposed.

Real Increase in Insurance Costs

We have not reviewed the proposed increase in insurance costs (Business Case S62) as it is not a technical matter.

Adjustment for Incremental Growth

Envestra has proposed adjustments to its level of operating expenditure over the next period to allow for forecast growth in its operations. It states that whilst the majority of its operating expenditure is fixed in the short term, an incremental cost of $38.57 per additional customer will be incurred. [72] We noted that this sum includes $17.60 for periodic meter change (PMC).costs. Periodic meter changes are treated by the business as a capital expenditure item and thus should not be included in this calculation. We also noted that costs associated with operations and maintenance were double the unit cost that Envestra incurs in South Australia. We agree that there will be additional costs but recommend that the same 2.5% p.a. compounding efficiency adjustment be applied to the incremental growth expenditure as was applied to base year expenditure.

We have not reviewed the customer growth forecasts that have been used as this was outside our terms of reference.

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[71] Rather than indicate a specific time, customers could be notified that the work will be carried out within a stated period, e.g. within the next week.

[72] AAI, section 6.7 p. 84.

Trade-Off between Operating and Capital Expenditure

We considered whether adequate attention had been given by Envestra to the trade-off between capital and operating expenditures. We concluded that the area with the most significant impact on future operating expenditure was capital expenditure on mains replacement and that, subject to the points we have raised, the resulting impact had been allowed for adequately in Envestra's expenditure proposal.

Conclusion in Relation to Cost Changes

The adjustments we have proposed in this section of the text are summarised in Table 6.8. The adjustments are expressed before the application of cost escalators with cost escalation then applied to the net adjustment (a reduction) in the same way as Envestra applied it to its total "non-base-year" costs.

Table 6.8: Recommended Adjustments ($2010 m)

YE 30 June	2012	2013	2014	2015	2016	**Total**
Non -base year expenditure reductions						
IT Costs	0.00	0.15	0.15	0.17	0.17	**0.63**
Leak Repairs	(0.00)	(0.04)	(0.07)	(0.11)	(0.15)	**(0.36)**
Nil gas consumption	0.05	0.01	0.01	0.01	0.01	**0.08**
Meter change notification	0.03	0.03	0.03	0.03	0.03	**0.16**
Knowledge management	0.00	0.15	0.15	0.15	0.15	**0.58**
	0.08	0.30	0.26	0.24	0.21	**1.10**
Cost escalation	0.00	0.01	0.02	0.02	0.02	**0.08**
	0.08	0.31	0.28	0.27	0.23	**1.17**
Incrmental Growth Reductions						
Removal of PMC	0.05	0.10	0.16	0.21	0.26	**0.77**
Efficiency adjustment	0.00	0.01	0.02	0.03	0.05	**0.11**
Total reduction	**0.13**	**0.42**	**0.46**	**0.51**	**0.54**	**2.06**

6.10 Recommended Operating Expenditure in Next Period

After taking account of the matters discussed in this section of the report, the operating expenditure that we consider prudent and efficient in the next period is $95.2 m, as shown in Table 6.9.

As we did not have sufficient information to be sure of the accuracy of our adjustments to remove the contingency allowances or to correct for the various escalation and growth factors involved the adjustments are our best estimates. Envestra should be asked to confirm our calculations or submit adjusted figures.

Table 6.9: Recommended Opex in Next Period ($2010 m)

YE 30 June	2012	2013	2014	2015	2016	**Total**
Opex as proposed by Envestra	21.6	22.1	21.4	21.1	20.8	**107.0**
Efficiency adjustments	(0.9)	(1.4)	(1.9)	(2.5)	(3.1)	**(9.7)**
Non-base year adjustments	(0.1)	(0.4)	(0.5)	(0.5)	(0.5)	**(2.1)**
Recommended	**20.6**	**20.3**	**19.0**	**18.2**	**17.2**	**95.2**

These adjustments should be accompanied by lower levels of UAFG in the next period than those projected by Envestra, as noted in section 6.7 .

7 Conclusion

7.1 Opinion

Having considered the information received from the business and the factors required to be considered as summarised in this report, and based on that information, the representations made to us by the business and our own experience, our opinion in respect of Envestra's expenditure proposals in relation to its network is as stated below.

(a) The level and pattern of capital expenditure in the present period is considered prudent and efficient.

(b) Adjustments are needed to the proposed level of capital expenditure in the next period, including a reduction in expenditure on mains replacement. The adjustments are summarised in section 4.9 of the report.

(c) The base-year level of operating expenditure is above an efficient level and we recommend that an annual compounding productivity improvement adjustment be applied to the base-year level throughout the next period. Details are given at the end of section 6.2 of the report.

(d) Adjustment is needed to several of the proposed "step changes" and other additional costs, including a reduction in Envestra's proposed savings attributable to reduced leak repairs. The latter is recommended in conjunction with a reduction in the capital expenditure proposed for mains replacement in the Brisbane network. Details are given in section 6.9 of the report.

(e) A reasonable level of unaccounted-for gas to be allowed in the next period would be the level that the business presently measures, *viz.* 0.6% of gas input for the Queensland networks as a whole or, expressed more correctly in quantitative terms, 92.3 TJ p.a.

The resulting recommended level of operating expenditure in the next period is summarised in section 6.10 of the report.

Various matters have been noted throughout the report for the AER's consideration – for example, in relation to the reasonableness of the level of capitalisation of overheads.

7.2 Qualifications of the Reviewers

Our opinion has been formulated for and on behalf of Wilson Cook & Co Limited by Mr Jeffrey Wilson with the support of Mr Peter Cole, Mr Derek Walker, Mr Pat Hyland and Mr Bernard Ivory. Mr Wilson is a professionally qualified engineer, experienced in undertaking reviews this type. Messrs Cole, Walker and Hyland are also professionally qualified engineers and Mr Ivory is a chartered accountant and economist. All team members are experienced in the energy sector and in assessments of this type. Curricula Vitae of the team members are attached.

7.3 Conditions Accompanying Our Opinion

Assessment Not an Assessment of Condition, Safety or Risk

Notwithstanding any other statements in this review, this review is not intended to be and does not purport to be an assessment of the condition, safety or risk of or associated with the business's assets and nothing in this report shall be taken to convey any such undertaking on our part to any party whatsoever.

All Earlier Advice Superseded

For the avoidance of doubt, we confirm that this report supersedes all previous advice from us on this matter, whether written or oral, and constitutes our sole statement on the matter.

Disclosure

Wilson Cook & Co Limited has prepared this report in accordance with the instructions of its client on the basis that all data and information that may affect its conclusions have been made available to it. No responsibility is accepted if full disclosure has not been made. No responsibility is accepted for any consequential error or defect in our conclusions resulting from any error, omission or inaccuracy in the data or information supplied directly or indirectly.

Disclaimer

This report has been prepared solely for our client, the Australian Energy Regulator (AER), for the stated purpose. Wilson Cook & Co Limited, its officers, agents, subcontractors and their staff owe no duty of care and accept no liability to any other party, make no representation or warranty as to the accuracy or completeness of the information or opinions set out in the report to any person other than to its client including any errors or omissions howsoever caused, and do not accept any liability to any party if the report is used for other than its stated purpose.

Non-Publication

With the exception of its publication by the AER, in relation to its review of the business's expenditure proposals, neither the whole nor any part of this report may be included in any published document, circular or statement or published in any way without our prior written approval of the form and context in which it may appear.

Appendix A: Curricula Vitae of Reviewers

CURRICULUM VITAE

Jeffrey Wilson **Engineering and Management Consultant, Adviser & Valuer**

Born	1947
Nationality	New Zealander
Education	ME, University of Auckland, 1970 BCom, University of Auckland, 1979 Courses and conferences locally and internationally on technical, managerial, leadership, governance and financial reporting matters, including IoD courses.
Languages	English : mother tongue Portuguese: reasonable reading ability, limited conversational ability French: reasonable reading ability, limited conversational ability
Professional Affiliations	FIET (UK), CEng (UK), FIPENZ, CPEng (NZ), MIEEE (USA) International Professional Engineer (IntPE) and APEC Engineer Member, New Zealand Association of Economists Member, Institute of Directors NZ
Countries of Work Experience	New Zealand, Australia. Europe: Portugal and Russia. SE Asia, the Pacific and Africa: Bangladesh, Bhutan, Cambodia, PR China, East Timor, Federated States of Micronesia, Fiji, India, Indonesia, Kyrgyz Republic, Laos, Malaysia, the Maldives, Mongolia, Nepal, Pakistan, Papua New Guinea, the Philippines, Samoa, Sri Lanka, Tanzania, Thailand and Vietnam.

Key Qualifications

Qualified in commerce and engineering.

Corporate governance experience, including chairmanship, since 1988, in electricity utilities, state-owned entities (Industrial Research Ltd), private companies, trust-owned companies and other bodies (listed on next page).

38 years of professional experience in engineering and management consulting, advisory work and valuations including corporate development and management training in utility businesses, power system planning, economic and financial evaluation of projects, economic and financial modelling and evaluations, asset and business valuations and management of major multi-disciplinary projects.

Adviser in New Zealand to electricity and gas utilities on valuation and regulatory matters.

Adviser in Australia to regulatory bodies in New South Wales, the ACT, Victoria, Tasmania, Western Australia and federally (the Australian Energy Regulator) in relation to expenditure projections and fixed asset valuations for price determinations. (Wilson Cook & Co is currently working in NSW, the ACT and WA.)

Adviser to the Independent Pricing and Regulatory Tribunal of NSW on various special assignments including prudential matters and economic and financial modelling of isolated combined heat and power schemes.

Power sector project experience as Project Director, Team Leader, Power Engineer or Economist on power planning and corporate and sector restructuring projects in S.E. and South Asia, Portugal, Tanzania and Russia from 1984 to 2003.

Experience in numerous due diligence investigations, project and business assessments, risk assessments and valuations.

Expert witness in the High Court on various matters from c.1976 to the present time.

Consultant to the World Bank and Asian Development Bank on project formulation and sector policy development. Experience includes 2 years on the staff of the Asian Development Bank.

Employment Record

From-To (Month/Year)	Employer/Position	Description of Duties
May 2003 – Present	Wilson Cook & Co Limited – Founder and Managing Director	Engineering and management consultants, advisers and valuers.
Sep 1983 – May 2003	Worley Consultants, Beca Worley International then Meritec Limited – Department Manager	Manager in charge of power planning and management consulting services, economic and financial evaluations and asset valuations, 1984-2003.
	Meritec Group Ltd – Director and Chairman	Member of Board of Directors of Meritec Group over various periods from 1987 to 2002. Chairman from 1998 – 2001.
	Companies in Public and Private Sector	Non-executive director. Various appointments in the energy and industrial sectors since 1990.
Sep 1981 – Sep 1983	Asian Development Bank – Project Engineer	Technical and economic evaluation of projects. Loan administration.
May 1974 – Sep 1981	Mandeno, Chitty & Bell – Senior Engineer/Economist then Partner	Management and direction of a wide range of design and construction projects from power generation to boiler plant and building services. Project evaluations.
May 1971 – May 1974	New Zealand Electricity Department – Assistant Electrical Engineer	Substation design and construction supervision. Power system operational studies.

Company Directorships

Company directorships in public and state-owned companies in the energy and industrial sectors as follows:

Counties Power Ltd	July 2000 – Present	
Industrial Research Ltd	July 1997 – June 2000	
Materials Performance Technologies Ltd	c. July 1998 – June 2000	a/
Supalink Ltd	November0 1997 – June 2000	a/
Mercury Energy Ltd	November 1993 – July 1994	b/
Geothermal Energy (NZ) Ltd	March 1990 – March 1991	
Meritec Group Ltd	Chairman, March 1998 – February 2001 Director, December 1995 – August 2002, February 1994 – August 1994, and February 1988 – February 1991	
Various private organisations, companies and trusts	President, director or trustee of various organisations and entities since around 1978.	

a/ IRL representative.
b/ Resigned due to conflict with consulting practice.

Experience in the Gas Sector

Valuation of Gas Distribution Network
November 2008 – Present

Review for IPART of Prudential Requirements related to Isolated Electricity Supplies in NSW
November 2007 – June 2008

Regulation and Valuation of Electricity and Gas Network Fixed Assets - Powerco
September 2006 – Present

Regulation and Valuation of Electricity and Gas Network Fixed Assets –Vector
April 2006 – Present

Audit of New Zealand's Infrastructure (Electricity and Gas)
September 2003 – December 2003

Valuation of Gas and Electricity Assets for Vector Ltd (for two years), United Networks Ltd, Orion Limited (for two years), Transpower Limited (for two years) and Unison Ltd
January 2002 – May 2003

Due Diligence of Gas and Other Network Assets (Confidential)
June 2002 – January 2003

Valuation of Gas Treatment Plants
2002

Review of Field Maintenance Services for Gas Networks
November 2001– January 2002

Sale and Purchase of Gas Network, New Zealand
December 1999 – April 2000

Asset Management Plan for Gas Distributor and Preparation of Gas Network Valuation Handbook
1994 – 2001

Confidential Valuation of High Pressure Gas Transmission Pipeline
c. 1998

Valuation of High Pressure Gas Transmission Network
1994

New Zealand and Australian Experience in the Regulatory Assessments etc

Technical Consultant to the Economic Regulation Authority of Western Australia for Review of Expenditure Forecasts of Western Power's proposed Second Access Arrangement
October 2008 – Present

Principal Technical Consultant to the Australian Energy Regulator for Review of Expenditure Forecasts of the ACT and NSW Electricity Distributors
November 2007 – Present

Adviser to Vector Limited on Expenditure-Related Matters
June 2008 – December 2008

Due Diligence Review – Technical Adviser
November 2007– April 2008

Review of Public Lighting Expenditures – Integral Energy
August 2007 – February 2008

Review of Aurora's Expenditures for Price Determination (Tasmania)

December 2006 – June 2007

Review of Audit Guidelines (NSW)
March 2007 – April 2007

Western Australia: Review of Western Power's Revised Expenditure Forecasts
March 2006 – September 2006

Consultant to IPART, NSW, for Cost Pass-Through Review
January – April 2006

Consultant to the Office of the Tasmanian Energy Regulator, for Mid-Term Review
August 2005 – February 2006

Consultant to the Economic Regulation Authority of Western Australia, for Review of Western Power's Asset Valuation and Expenditure Forecasts
August 2005 – January 2006

Principal Technical Consultant to Essential Services Commission, Victoria, for EDPR 2006
October 2004 – October 2005

Consultant to IPART, NSW, for Review of EnergyAustralia's Public Lighting Expenditures
June 2005 – August 2005

Review of Western Power's Estimates of Capex and Opex
February 2004 – May 2004

Review of DNSPs' Revised Estimates of Capex and Opex
January 2004 – May 2004

Submissions to Commerce Commission
February 2004 – April 2004

Appointment to Western Australian Electricity Sector Reform Panels
October 2003

Review of Electricity Distributors' Capital and Operating Expenditures for NSW Regulator
December 2002 – September 2003

Capital Expenditure Reviews for Regulatory Purposes
May 1998 – November 1998

Asset Management Plan and Long Term Network Development Plan Update for WEL Energy Group
August 1996 – January 1998

NSW State Government – Guidelines for Valuation of Network Fixed Assets
May 1995 – January 1996

New Zealand and Australian Energy Sector
1991 – 2000
Consultant to over 30 power utilities and energy companies in Australasia

New Zealand Power Sector
October 1983 – December 1991
Consultant

International Experience in the Electricity Sector

Details of Mr Wilson's experience internationally are available on request.

Other Experience

Details of Mr Wilson's other experience are available on request.

Publications and Papers

4. "Use of high-temperature water for the transport and distribution of heat", Trans. NZIE, 1981 (with B G Smith).
10. "Economic decision-making", Technical Forum, Auckland, April 1987 (with I.L. Wilson).
13. "Small isolated power systems - the issues", proceedings of Minerals and Energy Forum, Pacific Economic Co-operation Conference Specialist Group Meeting, August 1990.
14. "Capital investment appraisal in New Zealand's power sector in the 1990's", ESEA Generation Forum, Rotorua, March 1992.
15. "Valuation and regulation of New Zealand electricity companies: progress and issues", 10th CEPSI Conference, Christchurch, 1994.
16. "Developing transparent, efficient and effective procurement processes for power infrastructure in APEC member economies - a comparative study report", APEC Energy Working Group Report and Workshop, May 1997 (with W Jamieson of Norton Rose) **(ACENZ silver award-winning project).**
18. "Asset management strategies for power distribution utilities", Conference on Best Practice Asset Management for Utilities, Wellington, October 1997 (with R T Clifton and D S Todd).
21. "Long term network planning - best practice features", EEA Annual Conference, Auckland, June 1998 (with P C White and R T Clifton).
23. "Asset management plans and security of supply in the New Zealand electricity distribution industry", EEA Forum, Wellington, September 1998.
24. "Aspects of risk analysis and electricity network planning", Conference on Risk Management for Utilities, Auckland, December 1998 (with R T Clifton and G C Horvath).
25. "Outsourcing of engineering design and network maintenance services", AESIEAP CEO's Conference, Cebu, November 1999 (with R Clifton, M Tucker and L Lorentz).
26. "Review of international best practice in power system planning in the New Zealand context (with particular reference to the choice of voltage levels for sub-transmission and distribution and security of supply planning criteria)", EEA Conference, Auckland, June 2000 (with M.J. Whaley and H Tong).
27. "New Zealand electricity sector reform – a review of current issues", CEPSI 2000, Manila, October 2000 (with M.J. Whaley).
30. "New Zealand's experience of 'de-regulated' electricity supply", CIRED 18th International Conference on Electricity Distribution, Turin, 6-9 June 2005.
31. "New Zealand's power sector regulatory environment – an update", CIRED 19th International Conference on Electricity Distribution, Vienna, 21-24 May 2007.
32. "How useful is your asset management plan?", NZ 2nd Annual Electricity Network Asset Management Summit, Wellington, 20-21 November 2007.

CURRICULUM VITAE

Peter Cole **Fuels and Energy Specialist (Gas Distribution)**

Born	1942
Nationality	New Zealand
Education	BE (Mechanical Engineering, 1st Class Honours), University of Auckland, 1972 MPhil, Massey University, 2007
Languages	English : mother tongue French: reading ability
Professional Affiliations	MIPENZ Chartered Professional Engineer (New Zealand)
Countries of Work Experience	New Zealand, Australia, Bangladesh, Indonesia, Malaysia, Niue, the Philippines, Samoa, Singapore, Thailand, Vietnam and the Yemen.

Key Qualifications

Qualified in mechanical engineering with 37 years of professional experience in engineering consulting, advisory work and asset valuations.

Adviser to governments, institutional and private clients on fuel- and energy-related policies, plans and designs.

Adviser on energy supply options, fuel selection and utilisation.

Specialist in gas reticulation and use.

Experienced in natural gas and LPG market studies, planning, distribution and utilisation matters.

Experienced in CNG/NGV planning, technology and implementation.

Experienced in the design of mechanical and energy-related services for hospitals, institutional and commercial buildings.

Experienced in the co-generation of heat and power.

Experienced in the assessment of projects, including risk assessment.

Experienced in the management of energy sector projects in New Zealand and overseas.

Expert witness on energy- and gas-related matters.

Corporate governance experience.

Familiar with international lending agency and regulatory requirements.

Employment Record

From-To (Month/Year)	Employer/Position	Description of Duties
Sept. 2001 - present	Empower Consultants Ltd – Energy Specialist/ Director	Specialist consultant for gas and energy sector projects in New Zealand and overseas. Consultant to Wilson Cook & Co Limited.
April 1979 - September 2001	Meritec Ltd – Director	Management of gas sector projects in New Zealand and overseas including distribution and utilisation (industrial conversion and CNG). Gas sector planning in New Zealand and overseas. Preparation of reports and studies on natural gas, NGV/CNG and LPG markets, distribution and utilisation. Planning and design of energy distribution and utilisation systems. Expert witness on energy and related matters.
February 1972 - April 1979	Meritec Ltd – Engineer/Senior Engineer	Design of mechanical and energy services for hospital, institutional and commercial buildings.
April 1968 - February 1972	Meritec International Ltd - Senior Draughtsman	Design draughting work - mechanical services.
February 1967 - April 1968	A & T Burt Ltd - Estimator & Contract Supervisor	Estimating for and supervision of building services contracts.
June 1965 - February 1967	Ward Construction Ltd - Draughtsman	General mechanical and structural draughting.
August 1964 - April 1965	United Baltic Corporation Ltd – Marine Engineer	Watch-keeping and general engine maintenance.
November 1959 -	New Zealand Shipping Co. Ltd - Marine Engineering Apprentice	

New Zealand and Australian Experience

Gas Network Valuation for Vector Limited
November 2008 – Present

IPART Review of Prudential Requirements related to Isolated Electricity Supplies in NSW
November 2007 – June 2008

Gas Network Fixed Asset Valuation for Powerco Limited
October 2006 - continuing

Gas Network Fixed Asset Valuation for Vector Limited

May 2006 – continuing

Use of Landfill Gas as a Boiler Fuel at Nelson Hospital
2003- 2007

Gas Supply Options Study for Powerco Limited
September 2005 to June 2006

Gas Valuation Advice for NZ Commerce Commission
2003 - 2004

Mid-Central Health Limited Gas Supply Contracts
1998- 2004

Gas Network Fixed Asset Valuation for Vector Limited
January - August 2003

Gas Network Due Diligence for Vector Limited
July- August 2002

Gas network Valuation Handbook for Ministry of Economic Development
2001

Gas Network Due Diligence for Siemens Limited
January - March 2001

Gas Supply Contract for Water Care Services Limited
2000

Cogeneration Studies for Various Clients
1990 to 2000

Gas Network Due Diligence for Vector Limited
December 1999 - April 2000

LPG Consultancy Services for Rockgas Limited
1978 to 1999

Audit of LPG Installation
1999

Comparative Fuel Study for Natural Gas Corporation
Completed 1998

Gas Network Due Diligence for United Networks Limited
1998

Expert Witness for Crown Law Office on Gas Pipelines
November 1996- July 1997

Adviser to Department of Inland Revenue
May 1995 - May 1996

Gas Pipeline Feasibility Study (Confidential)
1996

Consulting Services to Capital Coast Health Ltd (Wellington) – Gas
1996

Landfill Gas Utilisation Study for Waitakere City Council
1993

Rockgas Limited
1986 – 1990

International Experience

Natural Gas Codes in Bangladesh
2005- 2006

Reduction of Vehicle Emissions in Jakarta
2003- 2005

Gas Sector Policy and Regulatory Framework for the Philippines
1998- 2002

Landfill Gas Utilisation in the Philippines
1999- 2001

Natural Gas Utilisation Project
1996 – 2000

Natural Gas as a New Energy Resource for the Philippines
July 1997 – December 1999

New Zealand Ministry of Foreign Affairs & Trade – Natural Gas Utilisation in Transport
1993 to 1999

LPG Substitution in Yemen
1994 – 1998

Feasibility Study of Options for Transport of Natural Gas
Completed 1986

Technical Audit of CNG Pilot Project
Completed 1986

Selected Papers

1. *"The New Zealand NGV programme and the lessons learnt"*, Technical Symposium and Investment Round Table on Transport Related Contracts for Natural Gas, ESCAP/Petronas, Kuala Lumpur, 1996.
2. *"Natural gas as an energy source for industrial and commercial buildings in ASEAN"*, ASEAN Energy Conference, Bangkok 1995.
3. *"The economics of compressed natural gas as a vehicle fuel- the New Zealand perspective"*, Petroleum Institute of Thailand conference: Gas Utilization Policies: an International Perspective, Pattaya, 1987.
4. *"Transport fuels in New Zealand – a new direction"*, World Energy Conference Regional Symposium, .Perth, 1986 (with RK Green, JK Raine, NB Smith and P Waring).

CURRICULUM VITAE

Derek Walker **Utility Management Adviser**

Born	1954
Nationality	New Zealander
Education	BE (Hons) (Electrical), University of Canterbury, 1975 BBS, Massey University, 1991 Various engineering and management training programmes, including Institute of Directors company director courses.
Languages	English : mother tongue
Professional Affiliations	Member, Institution of Professional Engineers, New Zealand Member Institute of Directors in NZ
Countries of Work Experience	Australia, New Zealand.

Key Qualifications

Qualified professionally in engineering and management.

25 years' experience in management and senior engineering roles in the distribution sector of the electricity supply industry, leading to a thorough understanding of, and practical experience in, all aspects of the industry including generation, wholesale market, retail, distribution and utilisation.

Development and utilisation of costing and pricing models for network and energy retail businesses.

Knowledge and experience in planning, designing, maintaining and operating urban and rural electricity distribution networks.

Considerable experience in negotiating and implementing major business transactions including mergers, acquisitions and sales.

High-level understanding and practical application of all business management disciplines including strategic and business planning, performance management, finance, accounting, treasury, legal, risk management, engineering, marketing and human resources.

Thorough knowledge and practical experience of governance responsibilities for both commercial and not-for-profit organisations.

Ability to see the "big picture" and think laterally and strategically.

Ability to develop and maintain a high performance management and organisation team culture in a changing environment.

Empathy with staff and customers giving an ability to build strong loyalty.

Excellent written and verbal communication skills and a high level of computer literacy.

Familiar with the Australian and New Zealand electricity supply industry.

Consultancy experience in multi-disciplinary teams since 2000.

Employment Record

From-To (Month/Year)	Employer/Position	Description of Duties
2001 – Present	Director and Principal, Third Bearing Ltd.	Business and management consulting and consultant to Wilson Cook & Co.
1989 – 2000	Chief Executive, CentralPower Limited (previously the Manawatu-Orua Electric-Power Board). Appointed Managing Director in November 1993.	Responsible for all aspects of the business's development and operation.
1981 – 1989	Ashburton Electric-Power Board. Substation and Distribution Engineer from 1981; Chief Engineer from 1986; and Commercial Manager from 1988.	Responsible, in final position, to the Chief Executive for all engineering, marketing and sales activities.
1979 – 1981	Electricity Division, Hamilton City Council. Design Engineer.	Responsible for electricity distribution network planning and design functions.
1975 – 1978	South Canterbury Electric-Power Board. Assistant Engineer.	Engineering planning, design, construction supervision and operational duties.

Company Directorships

Directorships or trusteeships in private and public companies and trusts in the energy sector and in other organisations as follows:

Spiers Group Limited	2007 – Present
Quotable Value Limited	2005 – Present
NZ Windfarms Limited	Director, 2004 – 2005. Chairman, 2005 – Present
Central Energy Trust	2003 – Present
The Bio Commerce Centre Limited	Chairman, 2003 – Present
Third Bearing Limited and associated companies	2001– Present
Palmerston North City Holdings	2000 – 2005
Palmerston North Airport Limited	Director, 2000 – 2002. Chairman, 2002 – Present
Manawatu Life Education Trust	Chairman, 1995 – 1997. Trustee, 1997 – Present.
Palmerston North Theatre Trust	Trustee, 1994 – 1998. Chairman, 1998 – 2006
Energy Brokers New Zealand Limited	Director, 1994 – 1996. Chairman, 1996 – 2000
Electricity Networks Association	1994 – 2000
CentralPower Limited and subsidiaries	1994 – 2000

Relevant Experience

Consultant to the Economic Regulation Authority of Western Australia for Review of Expenditure Forecasts of Western Power's proposed Second Access Arrangement

October 2008 – Present

Consultant to the Australian Energy Regulator for Review of Expenditure Forecasts of the ACT and NSW Electricity Distributors

November 2007 – Present

Review of Prudential Requirements related to Isolated Electricity Supplies in NSW

November 2007 – June 2008

Brief Review of Projected Expenditures Arising from National Electricity Market (NEM) Responsibilities (Tasmania)

June 2007 – July 2007

Review of Aurora's Expenditures for Price Determination (Tasmania)

December 2006 – June 2007

Western Australia: Review of Western Power's Revised Expenditure Forecasts

March 2006 – September 2006

Review of Cost Pass-Through Expenditures of NSW DNSPs for IPART

January – April 2006

Consultant to the Office of the Tasmanian Energy Regulator, for Mid-Term Review

August 2005 – February 2006

Consultant to the Economic Regulation Authority of Western Australia, for Review of Western Power's Asset Valuation and Expenditure Forecasts

August 2005 – January 2006

Principal Technical Consultant to Essential Services Commission, Victoria, for EDPR 2006

October 2004 – October 2005

Business and Management Consulting

Director and Principal, Third Bearing Limited

Grid Security Committee (New Zealand)

Committee Member
1999 – 2000

Electricity Distribution Business Experience

Various positions, including Chief Executive then Managing Director of CentralPower Ltd
1975 – 2000

CURRICULUM VITAE

Patrick Hyland **Asset Management Specialist**

Born	1957
Nationality	New Zealand and Canadian
Education	BE (Hons) (Electrical), University of Canterbury, 1979 ME (Electrical), University of Canterbury, 1980 *Training Courses:* “Construction contracts”, a course on contract law with an emphasis on NZS 3910. “Project evaluation”, a course on the financial evaluation and risk assessment of projects by Arthur Young Associates. “Management skills”, a two-week course with emphasis on management by objectives. “ISRS orientation and management training”, a three-day course on the International Safety Rating System. “Industrial relations”, a two-day course by consultant Mr P Meuli. “Process Control”, a four-day course by Engineering Information Transfer. “Interaction management”, a five-day trainer’s course in teaching the Interaction Management programme by Mentor Human Resource Group Ltd. “Authorisation holder’s certificate (power plant)”, a course for authorisation to work on operational power plant. First aid and CPR certification and subsequent revalidations. “Power system dynamic simulation”, a six-day course by Dr J Undrill.
Languages	English : mother tongue
Professional Affiliations	Member, Electricity Engineers Association (New Zealand).
Countries of Work Experience	New Zealand, Australia.
Key Qualifications	Qualified in electrical engineering. 27 years of professional experience in power engineering and in project management. Experience initially in generating plant and transmission networks, then in distribution networks. Experience in due diligence investigations, numerous project and business assessments, risk assessments and reviews. Experience in the preparation and review of asset management plans. Has specialised in the assessment of network service delivery and the prediction of asset lives. Has also specialised in analytical work and the assessment of risk. Adviser to several of New Zealand’s largest generation and network businesses. Adviser to network businesses in Australia.

Author of several published papers in these fields (listed at the end of this CV).

Winner of industry award for a project in automation and control (the Association of Consulting Engineers of New Zealand's Silver Award of Merit, 1992).

Employment Record

From-To (Month/Year)	Employer/Position	Description of Duties
December 2005 to Present	Hyland McQueen Ltd – Principal.	Consultancy services to the power industry. Consultant to Wilson Cook & Co Limited.
May 1995 to December 2005	Austral Engineering Associates Ltd – Principal.	Consultancy services to the power industry.
June 1992 to December 1994	Worley Consultants Ltd – Senior Engineer.	Responsible for project management and detailed design of projects for the power industry.
September 1987 to June 1992	Electricity Corporation of New Zealand – Group Electrical Engineer, South Island Hydro.	Responsible for various major projects and electrical standards at power stations in the South Island.
May 1986 to August 1987	New Zealand Electricity Department – Project Manager.	Responsible for the detailed design, procurement and construction of the $10 million refurbishment of the Roxburgh 220 kV switchyard.
March 1981 to April 1986	New Zealand Electricity Department – Assistant Engineer.	Steam-field electrical design for Ohaaki geothermal power project; substation design standards, HVDC and filter bank controls and maintenance engineering.

Experience in the Electricity Sector

Consultant to the Economic Regulation Authority of Western Australia for Review of Expenditure Forecasts of Western Power's proposed Second Access Arrangement

October 2008 – Present

Consultant to the Australian Energy Regulator for Review of Expenditure Forecasts of the ACT and NSW Electricity Distributors

November 2007 – Present

Due Diligence Assessment of the Orion Gas Network

February 2000 to March 2000

Advice to Vector Limited on Expenditure-Related Matters

June 2008 – December 2008

Review of Asset Management Planning Documents

November 2007 to Present

Maintenance Optimisation Review

August 2007 to November 2007

Translating Generator Condition to Risk
May 2007 to August 2007

Insurance Risk Model Assumptions Measurement
June 2007 to July 2007

Tariff Meter Management Review
January 2007 to March 2007

Review of Asset Management Planning Documents
November 2006 to January 2007

Creation of Life-Cycle Models for Generation Plant
February 2006 to August 2006

Generation Embedding Risk
May 2006 to July 2006

Network Maintenance Contract Pricing for Lines Company
January 2006 to March 2006

Creation of Asset Management / Risk Management Software System
August 2005 to September 2006

Life Cycle and Risk Modelling Integration Project
December 2004 to October 2006

Impact Assessment of Energy-Efficient Lights on Networks
August 2004 to September 2005

Independent Review of Electricity Metering Plan – United Energy Distribution Ltd, Australia
February 2005

Engineering Overview for New Generation Proposal
December 2004 to March 2005

Hydro Generator Life Prediction
August 2004 to November 2004

Asset Management Assessment for Marsden B Power Station
January 2004 to April 2004

Cost and Risk Assessment for Due Diligence
February 2004

Asset Management Strategy Development
January 2004 to March 2004

Plant Risk Model Redevelopment
October 2003 to May 2004

Maintenance Contract Costing Model
September 2003 to December 2003

Line Charge Assessment
July 2003

Development and Drafting of Asset Management Plan
March 2003 to May 2003

Maintenance Processes Audit
August 2002 to September 2002

Network Reliability Modelling for Setting Network Maintenance Service and Capital Development Requirements

November 2002 to December 2002

Drafting 2003/04 Asset Management Plan

August 2003 to September 2002

Due Diligence Assessment of the Asset Planning of CitiPower Limited, Melbourne

June 2002 to July 2002

Develop Business Case for Rollout of Maximo CMMS

August 2001 to January 2002

Development of an Assets Inspection Data Collection Process

May 2001 to September 2001

Distribution Transformer Maximum Demand Approximation

February 2001 to May 2001

Capital Projects Database

November 2000 to March 2001

Development of "PlantRisk" Model for Asset Replacement Forecasting

June 2000 to February 2001

Drafting Asset Management Plan Describing Asset Replacement Requirements

August 2000 to December 2000

Sale of Contracting Division – Preparation of Maintenance Schedules

May 2000 to August 2000

Drafting an Asset Management Plan for Network Waitaki Ltd

August 1999 to November 1999

Maintenance and Replacement Documentation for United Energy Ltd – Melbourne

September 1999 to November 1999

Risk Statement for UnitedNetworks Ltd

July 1999 to October 1999

Reliability Forecasting Model for United Energy Ltd – Melbourne

June 1999 to October 1999

Weather Normalisation of Network Reliability Data for United Energy Ltd – Melbourne

April 1999 to May 1999

Asset Management Philosophy and Revision of the Asset Management Plan

February 1999 to April 1999

Compliance Testing Strategy for Domestic Metering for United Energy Limited – Melbourne

August 1998 to April 1999

Due Diligence Assessment of Electricity Network for United Networks Limited

September 1998 to December 1998

Overhead Line Reliability-Centred Maintenance Review for United Energy Limited – Melbourne

February 1998 to September 1998

Network Information System Review for Power New Zealand Limited

July 1997 to December 1997

Distribution Transformer Maintenance Strategy and Cost Model for Power New Zealand Limited

April 1997 to July 1997

Substation Database Design for Power New Zealand Limited
January/February 1997

Subdivision Design Review for Power New Zealand Ltd
July 1996 to December 1996

Maintenance Review for Power New Zealand Ltd
May 1995 to July 1996

Power Station Manuals Preparation
May 1994 to November 1994

Revenue Metering Project
July 1992 to March 1994

Revenue Metering Project
September 1991 to July 1992

Publications and Papers

1. Densem & Hyland, "Out of condition or condition drives assets", paper presented to EEA Conference, July 1996.
2. Densem, Hyland, Cochrane Whatley & Zonneveld, "Identify the maintenance risks or pay the cost", paper presented to Distribution 2000 Conference, Sydney, November 1997.
3. Hyland & Moffat, "Road-testing meter compliance", paper presented to EEA Conference, June 1999.
4. Hyland & McQueen, "What's that creeping up on you", paper presented to EEA Conference on distribution transformer management, June 2002.
5. McQueen M, Hyland & McQueen D, "An alternative to distribution transformer maximum demand recording", paper presented to Distribution 2003 Conference, Adelaide, November 2003.
6. McQueen, Hyland & Watson, "Monte Carlo simulation of residential electricity demand for forecasting maximum demand on distribution networks", IEEE Trans. PES, January 2004.
7. McQueen, Hyland & Watson, "Application of a Monte Carlo simulation method for predicting voltage regulation in low voltage networks", IEEE Power Engineering Society, July 2004.
8. Hyland, "Living with uncertainty: managing capital and maintenance expenditure for network reliability", 1st Annual Electricity Networks Asset Management Conference, Wellington, November 2006.
9. Hyland, "Asset replacement planning – one size does not fit all", 2nd Annual Electricity Networks Asset Management Conference, Wellington, November 2007.

CURRICULUM VITAE

Bernard Ivory **Financial Analyst / Economist**

Born	1932
Nationality	New Zealander
Education and Training	Bachelor of Commerce (Accountancy & Economics) University of New Zealand 1955 Professional examinations of The Institute of Chartered Accountants of NZ (1953) and of The Chartered Institute of Corporate Management (NZ) (1954) Other training: industrial engineering, cost and management accounting and budgetary control, marketing, supervisory and management training and development in-house with employer. Professional examinations of the NZ Institute of Valuers 1974-1980 (sat and passed 13 of 14 units)
Languages	English: mother tongue
Professional Affiliations	Institute of Chartered Accountants NZ (Hon ACA retired) 1953-2005 The Chartered Institute of Corporate Management (NZ) (CCM) 1954-2001 Institute of Chartered Management Consultants NZ (CMC) 1974-1999 Institute of Directors NZ (Fellow) 1972-2001
Countries of Work Experience	Australia, Bangladesh, Bahrain, Bhutan, Cambodia, East Timor, Fiji, Indonesia, India, Kiribati, Laos, Maldives, Malaysia, Mongolia, Nauru, New Zealand, Pakistan, Philippines, Singapore, Sri Lanka, Solomon Islands, Thailand, Tonga, Tuvalu, USA, Vanuatu, Vietnam.
Key Qualifications	More than 30 years of professional experience in financial and economic analysis and management consulting with an emphasis in the last 20 years on the electricity supply industry. Experienced in the preparation and assessment of financial models of companies and projects.

Employment Record

From-To (Month/Year)	Employer/Position	Description of Duties
May 2003 – Present	Consultant to Wilson Cook & Co Limited.	Financial analyst and management consultant.
1962 - 1972 then 1974 - 2005	PA Consulting Group, Australia and New Zealand.	Specialised in the fields of financial and economic analysis, management information and systems, institutional development and strategic business and country planning.
1972 - 1974	Lockwood Buildings Ltd.	Rotorua, NZ, General Manager.
1952 - 1962	Skellerup Industries Ltd.	Christchurch, NZ, Company Secretary and Accountant.

Experience in the New Zealand and Australian Electricity Sectors

Consultant to the Economic Regulation Authority of Western Australia for Review of Expenditure Forecasts of Western Power's proposed Second Access Arrangement

October 2008 – Present

Consultant to the Australian Energy Regulator for Review of Expenditure Forecasts of the ACT and NSW Electricity Distributors

November 2007 – Present

Review of Prudential Requirements related to Isolated Electricity Supplies in NSW

November 2007 – Present

Electricity Distributors' Cost Pass-Through Application – Review for IPART

January 2006 – April 2006

Economic Regulation Authority of Western Australia – Review of Western Power's Asset Valuation and Expenditure Forecasts

August 2005 – January 2006

Office of the Tasmanian Energy Regulator – Mid-Term Review

August 2005 – February 2006

Review of DNSPs' Revised Estimates of Capex and Opex for NSW Regulator (IPART)

September 2003 – October 2003

Review of Electricity Distributors' Capital and Operating Expenditures for NSW Regulator (IPART)

December 2002 – September 2003

Review of Customer Capital Contributions for Electricity Connections (for IPART)

March 2001 – October 2001

Waikato Energy Group: Pricing Network Services, Hamilton, NZ

1994

Transpower Ltd – Review of Proposed Pricing Policies

1991

International Experience in the Electricity Sector

Establishment of New Management Contract for EDTL

November 2006 – March 2007

Corporatisation of the Bangladesh Power Development Board, Dhaka, Bangladesh

2006 – 2007

Update of the Electricity Tariff Rationalisation Study for PT PLN (Persero)

2004

Preparation of the Assam Power Sector Development Programme, Guwahati, India

2003

Implementation Framework for IPP Projects Outside Java-Bali

2002-2003

Governance and Institutional Support for Private Sector Development, Sri Lanka

2002

Third Power Project Rehabilitation Loan, Sri Lanka

2001

Power Sector Restructuring, Sri Lanka

2000-2001

Evaluation of Hydropower Proposals, Solomon Islands Electricity Authority
1999

Privatisation Study of Electricity and Water Assets, Bahrain
1998

World Bank/Privatisation Commission of Pakistan
1997

Corporate and Financial Development of Electricité du Laos
1996-1997

Institutional Strengthening of Fiji Electricity Authority
1996-1998

Review of Technical and Financial Performance of Assam State Electricity Board, India
1992

Financial and Organisational Restructuring of Karachi Electric Supply Corporation
1992

Establishment of Lanka Electricity Co (Private) Ltd, Sri Lanka
1985-1987