Australian Energy Regulator

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

(Public Version)

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 (SOUTH AUSTRALIA)

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 South Australian 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 prudent and efficient, reflecting the expected completion of substantially all the proposed mains replacement work foreseen at the start of the period, the continued connection of new customers and the deferral of various augmentation projects. Underruns in expenditure in individual categories were significant but Envestra appears to have managed its expenditure carefully, making reductions in discretionary items to reduce its overall level. This was a reasonable and appropriate response in a period when external factors (particularly the global financial crisis) put the business under financial pressure.

(b) The principal expenditure in the next period is on the proposed mains replacement programme. Envestra has proposed that this programme be continued but at a faster rate. Whilst a sound case has been made for the work, we consider that the accompanying, forecast rate of reduction in unaccounted-for gas is insufficient and so have proposed a faster rate for its reduction.

(c) We note that the business may react to the effects on UAFG of mains replacement work as it proceeds by modifying the rate of replacement accordingly and we consider that this would be a valid response, as it is optimality of the cost of leakage *vs.* mains replacement cost that should be sought, not leakage reduction for its own sake. We suggest to the AER that this possibility be considered in its decision.

(d) Other than in these respects, the proposed capital expenditure in the next period reflects a catch-up in mains augmentation work 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 the present period was substantially at its forecast level. Variances in individual categories were significant but Envestra appears to have managed its expenditure carefully, making reductions in discretionary items to offset increases in non-discretionary operating expenditure that arose from deferral within the period of mains replacement expenditure. As in the case of capital expenditure, this was a reasonable and appropriate response in a period when external factors put the business under financial pressure.

(b) The proposed base-year level of expenditure is considered efficient, based on our analysis, but we have recommended adjustments in several of the proposed "step changes" and additional costs.

(c) In addition, an adjustment will be required to reflect the more rapid reduction in UAFG that we foresee and have referred to above.

(d) Envestra has proposed a large increase in the price of gas for UAFG in the next period and an increase in marketing expenditure. These matters account for about half of the proposed increase in operating expenditure but are not technical in nature and so have not been reviewed by us.

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

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 (South Australia)

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 South Australian 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*.

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 South Australian 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 on 21-22 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 around 1861 when the South Australian Gas Company was formed to reticulate manufactured gas. It now serves about 396,000 customers in Adelaide, Mt Gambier, Whyalla, Port Pirie, the Barossa Valley, Murray Bridge and Berri. [12]

It transports about 15.2 PJ of gas p.a. to 146 large customers who each consume more than 10 TJ p.a. and 8.6 PJ of gas p.a. to the remaining customers, as summarised in Table 2.1.

Growth in the number of connections is forecast to continue over the next period at approximately 7,700 p.a., a rate of increase of 1.18% p.a. [13] Consumption per residential customer is expected to continue to fall (at a rate of 3% p.a. over the next period) and the total throughput is expected to decrease as well, at approximately 2% 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.195 (rate of increase).

[14] Sources: AAI, p.197 (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)	385,816	97%	7,544	32%
< 10 TJ p.a. – Volume Customers (Commercial)	9,812	2%	1,103	5%
	395,628	**100%**	**8,647**	**36%**
≥ 10 TJ p.a. – Demand Customers	146	0%	15,195	64%
	395,774	**100%**	**23,842**	**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)
Adelaide	7,112
South East	201
Whyalla	102
Port Pirie	126
Murray Bridge	32
Nuriootpa	27
Berri	19
Other	26
Total	**7,645**

Source: AAI, p. 9.

Gas is delivered via 13 gate stations of which four serve metropolitan Adelaide. The remainder serve Angaston, Freeling, Mt Gambier, Nuriootpa, Peterborough, Port Pirie, Waterloo, Whyalla and Virginia. [15] In addition, there are 12 "farm taps" supplying single industrial consumers directly from EPIC's Moomba and Katnook pipelines.

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	1,954
Medium	2,444
High	3,047
Transmission a/	200
Total	**7,645**

Source: AAI, p. 9.
a/ Transmission pressure refers to distribution mains operating at a pressure of 1,050-1,750 kPa.

[15] Gas supply for all networks except Mt Gambier is taken from the Moomba- to-Adelaide Pipeline (MAP). A second supply for the Adelaide metropolitan network and the supply to Mt Gambier are taken from the Port Campbell-to-Adelaide pipeline (the SEAGas Pipeline). A second supply to Mt Gambier is taken from the Katnook-to-Mt Gambier pipeline.

Of the pipes in use, 56.5% (4,316 km) are polyethylene, 26.5% (2,023 km) are steel, 17% (1,305 km) are cast iron and a small length of about one km is in copper. [16]

Unaccounted-for gas (UAFG) in FY 2011 is projected to be about 2.2 PJ p.a. or 8.3% of gas input excluding the supply to “farm taps”. [17]

The business estimates that 80% of the UAFG is attributable to leakage from the cast iron and unprotected steel mains still in service. [18]

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.

16 AAI, p.8.

17 Gas deliveries to the “farm taps” account for about 27% of total sales.

18 Source: AAI, attachment 7.2 (AMP) p.32 (UAFG) and attachment 13.1 (NIEIR), table 7.2 (throughput from which input is calculated).

3 Capital Expenditure in Present Period

3.1 Summary of Expenditure

Capital expenditure in the present period is projected to be $197.2 m compared with $233.2 m approved by the ESCOSA in its last decision, a decrease of $35.9 m or 15%. A breakdown of the expenditure by category is in Table 3.1. [19]

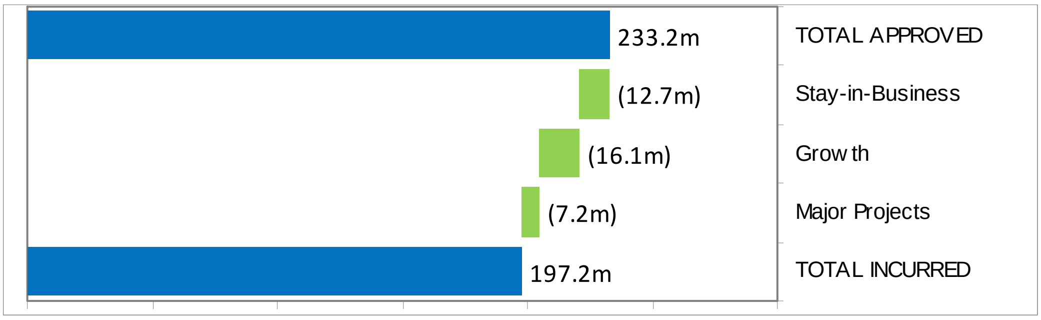
Table 3.1: Capex in Present Period vs. Decision ($2010 m)

		FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	**Total**
Stay in Business	Approved	20.4	21.0	21.7	14.7	17.8	**95.5**
	Incurred	14.8	18.7	14.1	14.3	21.1	**82.9**
	Variance	(5.6)	(2.3)	(7.6)	(.5)	3.3	**(12.7)**
Growth	Approved	26.9	28.6	20.5	25.3	22.7	**124.0**
	Incurred	22.4	21.9	21.0	19.2	23.3	**107.9**
	Variance	(4.5)	(6.7)	.6	(6.1)	.6	**(16.1)**
Major Projects	Approved	.0	.0	5.1	4.3	4.3	**13.6**
	Incurred	.0	.0	3.0	1.4	2.0	**6.4**
	Variance	.0	.0	(2.1)	(2.8)	(2.3)	**(7.2)**
Total	**Approved**	**47.3**	**49.6**	**47.3**	**44.3**	**44.7**	**233.2**
	Incurred	**37.2**	**40.6**	**38.1**	**34.9**	**46.3**	**197.2**
	Variance	**(10.1)**	**(9.0)**	**(9.1)**	**(9.4)**	**1.6**	**(35.9)**
		-21%	**-18%**	**-19%**	**-21%**	**4%**	**-15%**

Source: AAI, p. 35, table3.5 (incurred); revised table 3.6 provided to AER (approved).
Figures may not add due to rounding.

Under-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 three-year period contracts for mains and other work commencing in FY 2011. This has resulted in an increase in

[19] 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 ESCOSA. [20]

3.2 Growth-Related Expenditure

Envestra forecasts growth-related expenditure, the largest expenditure category in the period, of $107.9 m, as shown in Table 3.2. The table shows that that there was an underrun of $16.1 m in comparison with the level approved by the ESCOSA.

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	.8	.9	.7	.7	.7	**3.7**
	Incurred	.0	.2	.0	.0	.5	**.7**
	Variance	(.8)	(.8)	(.7)	(.7)	(.2)	**(3.0)**
Improved Supply	Approved	5.7	5.1	1.0	5.0	2.1	**18.9**
	Incurred	.0	.0	.0	.4	.8	**1.2**
	Variance	(5.7)	(5.1)	(1.0)	(4.6)	(1.4)	**(17.7)**
General Mains	Approved	6.7	7.3	6.1	6.3	6.5	**32.9**
	Incurred	7.5	6.4	6.8	4.3	5.0	**30.0**
	Variance	.8	(.9)	.7	(2.0)	(1.5)	**(2.8)**
Regulators	Approved	.0	.0	.0	.0	.0	**.0**
	Incurred	.0	.0	.0	.0	.4	**.4**
	Variance	.0	.0	.0	.0	.4	**.4**
Meters	Approved	4.3	4.6	3.8	3.9	4.0	**20.5**
	Incurred	3.6	3.8	3.7	4.1	4.4	**19.5**
	Variance	(.7)	(.8)	(.1)	.2	.4	**(1.0)**
Services	Approved	9.3	10.6	8.8	9.3	9.3	**47.3**
	Incurred	11.1	11.6	10.6	10.5	11.7	**55.4**
	Variance	1.8	1.0	1.8	1.1	2.4	**8.1**
Other	Approved	.2	.2	.2	.2	.2	**.8**
	Incurred	.2	.0	.0	.0	.6	**.8**
	Variance	.0	(.2)	(.2)	(.2)	.4	**(.0)**
Total	**Approved**	**26.9**	**28.6**	**20.5**	**25.3**	**22.7**	**124.0**
	Incurred	**22.4**	**21.9**	**21.0**	**19.2**	**23.3**	**107.9**
	Variance	**(4.5)**	**(6.7)**	**.6**	**(6.1)**	**.6**	**(16.1)**
		-17%	**-23%**	**3%**	**-24%**	**3%**	**-13%**

Source: AAI, p. 35, table3.5 (incurred); revised table 3.6 provided to AER (approved).
Figures may not add due to rounding.

The table and Figure 3.2 show that the principal under-spending occurred under the heading 'improved supply', *viz.* mains reinforcement and major extensions. General mains expenditure, along with the installation of meters and regulators showed little variance and expenditure on services showed a 17% increase. New connections for large customers did not reach the forecast level – not surprising, in the prevailing economic climate at the time.

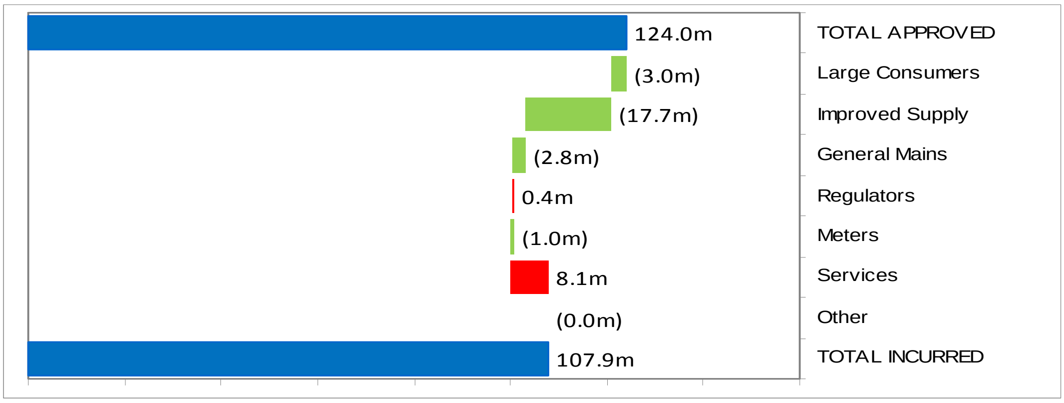
The total of new connections exceeded the number forecast by the ESCOSA by a small margin (0.75%) – see p. 28 of the AAI.

The combination of these factors – an underrun in total cost and a higher-than-projected number of connections actually made – indicates that a lower-than-projected level of average

[20] AAI, attachment 7.1 (capital expenditure and unit rates), p. 1. Most rates were affected by the re-tendering, with increases in labour costs of up to 45%.

cost per connection was achieved in the period. This is thought to be due, in turn, to a focus on making new connections (at least, in general) involving the least amount of mains extension or augmentation work. This explanation appears to be consistent with the accompanying, large under-spending evident in the "improved supply" category (which predominantly involves mains reinforcement) whereas variances in expenditure on general mains, regulators, meters and 'other' are minimal.

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



A more detailed review would be required to confirm the efficiency of the connection work undertaken. However, based on: the facts just cited, noting 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.

3.3 Stay-in-Business Expenditure

Details of stay-in-business expenditure, the second-largest category in the present period, are shown in Table 3.3. There is an underrun of $12.7 m in the category, although expenditure on its biggest component, mains replacement, increased.

Of the total expenditure of $82.9 m incurred, 89% is accounted for by three categories: mains replacement (58%), domestic meter replacements (17%) [21] and a category called "other" (14%). The remaining 11% is accounted for by the minor categories shown in the table.

[21] Referred to by Envestra as "periodic meter changes" or "PMC".

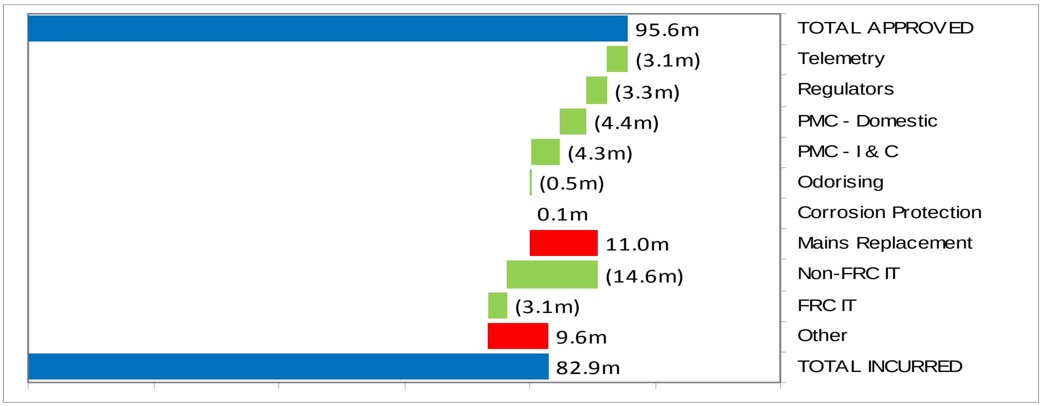
Table 3.3: Stay-in-Business Expenditure in Present Period ($ 2010 m)

		FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	**Total**
Telemetry	Approved	1.4	1.4	.7	1.3	.8	**5.6**
	Incurred	.7	1.0	.2	.3	.3	**2.5**
	Variance	(.7)	(.4)	(.6)	(1.0)	(.5)	**(3.1)**
Regulators	Approved	1.5	1.5	.8	.8	.8	**5.4**
	Incurred	1.0	.4	.1	.2	.4	**2.1**
	Variance	(.6)	(1.1)	(.7)	(.6)	(.4)	**(3.3)**
PMC - Domestic	Approved	3.9	4.1	3.9	3.8	3.2	**18.9**
	Incurred	2.2	3.4	3.2	2.9	2.7	**14.5**
	Variance	(1.8)	(.7)	(.7)	(.9)	(.5)	**(4.4)**
PMC - I & C	Approved	1.2	.9	1.4	1.4	1.3	**6.4**
	Incurred	.3	.5	.4	.4	.4	**2.0**
	Variance	(.9)	(.5)	(1.0)	(1.0)	(1.0)	**(4.3)**
Odorising	Approved	.1	.5	.1	.1	.1	**.7**
	Incurred	.0	.3	.0	.0	.0	**.3**
	Variance	(.1)	(.2)	(.1)	(.1)	(.1)	**(.5)**
Corrosion Protection	Approved	.1	.0	.1	.0	.1	**.2**
	Incurred	.0	.0	.0	.0	.3	**.3**
	Variance	(.1)	(.0)	(.1)	(.0)	.2	**.1**
Mains Replacement	Approved	7.8	7.5	6.9	7.1	7.7	**37.0**
	Incurred	6.3	10.0	8.0	8.6	15.1	**48.0**
	Variance	(1.5)	2.5	1.1	1.5	7.4	**11.0**
Non-FRC IT	Approved	4.0	4.6	7.3	.0	.0	**15.9**
	Incurred	.2	.6	.0	.0	.5	**1.4**
	Variance	(3.8)	(4.0)	(7.3)	.0	.5	**(14.6)**
FRC IT	Approved	.1	.1	.2	.0	3.5	**3.8**
	Incurred	.2	.5	.0	.0	.0	**.7**
	Variance	.1	.5	(.2)	.0	(3.5)	**(3.1)**
Other a/	Approved	.3	.3	.3	.3	.3	**1.6**
	Incurred	3.9	1.8	2.1	1.9	1.4	**11.2**
	Variance	3.6	1.5	1.8	1.6	1.1	**9.6**
Total	**Approved**	**20.4**	**21.0**	**21.7**	**14.7**	**17.8**	**95.6**
	Incurred	**14.8**	**18.7**	**14.1**	**14.3**	**21.1**	**82.9**
	Variance	**(5.6)**	**(2.3)**	**(7.6)**	**(.5)**	**3.3**	**(12.7)**
		-27%	**-11%**	**-35%**	**-3%**	**19%**	**-13%**

Source: AAI, p. 35, table3.5 (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

The largest component of stay-in-business expenditure in the present period relates to mains replacement. The projected expenditure on this item is $48 m compared with an approved level of $37 m – a variance of $11 m or 30%.

Envestra proposed (and the ESCOSA accepted) a proposed length of mains replacement of 500 km at an average of 100 km p.a. over the period. In total, 491 km of the work is expected to be completed. [22]

Envestra proposed a rate of $83 per metre in FY 2006 dollars for the work [23] but the ESCOSA reduced the rate to $65 per metre in its determination. [24] Escalating Envestra's proposed rate to FY 2010 dollars at 2.5% p.a. and applying it to the 491 km of work expected to be completed gives a total cost for the completed work of $45 m or 94% of the reported final cost.

Given the ESCOSA'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 and the documents and explanations we received from Envestra, we considered the expenditure prudent and efficient.

Domestic Meter Replacements

The cost of periodic changing of domestic meters was the second-largest component of stay-in-business expenditure in the present period. The projected expenditure on this item, whether through replacing a meter with a new meter or a refurbished one, is expected to be $14.5 m in the period compared to an approved amount of $18.9 m – a reduction of $4.4 m or 23%.

Meter changes are managed in accordance with the regulatory requirements applicable in the State. We understand that they stipulate a 10-year period for domestic meters before testing unless otherwise approved by the Office of the Technical Regulator. [25]

Envestra states that meters returned from the field are tested and are either repaired and re-used if economic or replaced.

The work is presently carried out by the APA Group under the operating and maintenance agreement with excess volumes of replacement work contracted out. [26]

Taking these factors into account, we consider the expenditure on meter replacement prudent and efficient.

Other Stay-in-Business Expenditure

The remaining categories of stay-in-business expenditure include "other", telemetry systems, regulators, industrial and commercial meter changeovers, odorising plant, corrosion protection and IT expenditure including expenditure related to the introduction of full retail contestability (FRC).

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[22] AAI, p. 99.

[23] AAI, p. 39.

[24] Source: *Proposed Revisions to the Access Arrangement for the South Australian Gas Distribution System – Final Decision*, ESCOSA, June 2006, p. 108. Also see the AAI, p. 39.

[25] Source: AAI, attachment 7.2 (AMP), p. 107. We refer to the Office of the Technical Regulator in the rest of this report as "the Office" or "the technical regulator".

[26] The AAI, p. 50 *et seq,* notes that the *Operating and Maintenance Agreement* was with Origin Energy Asset Management at the commencement of the present period but was re-negotiated in 2007 when the APA Group purchased the business.

Together, expenditure on these items is expected to be $20.4 m in the period compared to an approved amount of $39.7 m – an underrun of $19.3 m, 49%. The biggest reduction was in non-FRC-related IT, where the bulk of the proposed expenditure of $15.9 m has essentially not been carried out and actual expenditure is projected to be only $1.4 m. This accounts for three quarters of the under-spending of $19.3 m. [27]

Variances in the other categories are immaterial individually and were not reviewed further, except for the variance in "Other". In that category, actual expenditure was $11.2 m compared to an approved level of $1.6 m. No details were provided initially of this "Other" category but, in response to a request from us for clarification, Envestra advised us that:

> The "Stay-in-Business – Other" category includes mains alterations, miscellaneous plant and equipment, vehicles and miscellaneous office and IT equipment (such as desktop computers, printers, etc). By its nature, [this] category is difficult to accurately forecast (especially the quantum of mains alteration works that will be required).
>
> The difference between the benchmark and actual expenditure for this category is primarily due to higher mains alterations works in the current period relative to that included in the benchmark.

Based on the explanation, 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 prudent and efficient.

3.4 Major Projects

The third category of capital expenditure in the present period is expenditure on major projects. There was an underrun of $7.2 m in this category because of the deferral of or changes in three projects in particular: the southern loop and eastern ring-main project; the Gawler augmentation project; and the outer harbour project. Expenditure on these projects appears in the next period in reduced, modified or substituted forms.

The southern loop and eastern ring-main projects are understood to have been the subject of a cost pass-through mechanism with Stage 1 ($4.8 m) and Stage 2 ($8 m) approved. The first stage was completed in the period but the second stage was deferred, as the foreseen industrial and commercial loads that required it have not materialised. The second stage is not now expected to be required in the next period. The following extract from the 2008-09 annual report of the Office of the Technical Regulator explains this further:

> During 2007-08, Envestra advised the Technical Regulator of some significant changes to its comprehensive augmentation program for the South Australian gas distribution system that had been outlined to the Technical Regulator in 2005-06. The changes were approved by the ESCOSA following consultation with the Technical Regulator. The changes include replacement of the originally proposed Eastern Ring Main (ERM) and Southern Loop (SLP) projects with a more cost effective alternative consisting of two main projects; the duplication of the existing transmission main in River Road, Port Noarlunga to be followed by the installation of a new gas injection point (City Gate Station) supplying gas into the Adelaide distribution network at Gillman, to ensure the security and reliability of the gas supply to customers in Adelaide's southern suburbs. During 2008-09, the Technical Regulator monitored the work progress of the duplication of the transmission pipeline in Port Noarlunga and was assured by Envestra that they will be able to complete the project by winter 2010.

The Gawler augmentation project ($6 m) related to a major housing development at Concordia that has been deferred and the project was replaced with a smaller development

[27] In its AAI, p. 37, Envestra confirms that its stay-in-business expenditure was curtailed in response to the prevailing financial situation.

closer to existing infrastructure in conjunction with local augmentation. The work will be concluded in the next period. [28]

The outer harbour project ($2 m) was modified in the same way.

We asked for a statement of the final cost of these and other major works in comparison with the cost estimates considered for the same works by the ESCOSA. This information was provided in a spreadsheet received on 26 November. [29] It gave details of the following works: Virginia Gate, Kidman Park, Mt Gambier, the outer harbour, River Road and Gillman Gate, Gawler augmentation, Brighton Grand Junction Road, the MAP-SEAGAS interconnection and Jetty Road (Largs Bay). The approved amount for these works was $28.9 m and the actual amount expended was $8.4 m. The expenditure actually made was considered prudent and efficient.

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.

We considered from the documents and our meetings 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. [30] 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

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[28] Envestra's business case No. S26 gives a history of this project.

[29] Provided in response to our questions of 19 November.

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

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 21 capital projects ranging in cost from $5,900 to $3.2 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 did not consider it necessary to request business cases for the projects in the present period (most of which are now complete or substantially so) but considered it more relevant to ask for a statement of the completed cost of major works, as discussed in section 3.4. We were interested principally in the major works in this regard, as routine works are by their nature generally both necessary and prudent, their design is seldom contentious and their cost-effectiveness is implicit in the use of competitively contracted rates.

We relied also on the explanations given in relation to the expenditure by the business in its AAI and at our meetings.

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 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 $197.2 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. [31]

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.

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[31] For example, an email received from the AER on 13 December, after our work was concluded, suggested that a further expenditure of $1.1 m would be required by the business in FY 2011 for replacement of part of a transmission main between Seacombe Gardens and Flagstaff Hill. We were then further 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 $180.2 m instead of $197.2 m.

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.

4 Capital Expenditure in Next Period

4.1 Summary of Proposed Expenditure

Capital expenditure in the next period is forecast to be $506.9 m compared with the forecast incurred level in the present period of $197.2 m, an increase of $309.6 m or 157%. A summary of the forecast expenditure is 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 just over half of the total proposed expenditure in the period and the growth-related expenditure categories account for a further 10%.

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

FY ->	2011	2012	2013	2014	2015	2016	Total
Mains - Replacement	15.1	19.8	50.2	51.5	52.3	52.7	**226.5**
Meters - Replacement	3.1	2.9	3.1	4.3	5.2	5.5	**21.0**
Mains - Augmentation	.8	16.3	6.0	1.4	5.6	.1	**29.3**
Telemetry	.3	.4	.4	.8	.4	.4	**2.3**
Regulators and Valves	.8	.8	.8	.8	.8	.8	**4.1**
IT	.5	3.8	2.0	2.7	2.0	.4	**10.9**
Mains - Growth	5.0	7.0	5.8	5.7	6.2	6.9	**31.6**
Inlets - Growth	11.7	16.9	14.5	14.5	15.8	17.4	**79.1**
Meters - Growth	4.4	5.6	5.1	4.3	4.8	5.4	**25.2**
Growth New Areas	.0	14.0	3.8	.6	.5	.4	**19.2**
Large Consumers	.5	.3	.5	.3	.3	.5	**2.0**
Other - Distribution System	3.6	10.2	11.3	9.0	9.1	9.2	**48.7**
Other - Non Distribution System	.6	2.5	1.3	1.4	.9	.9	**6.9**
Total	**46.3**	**100.3**	**104.7**	**97.3**	**104.0**	**100.6**	**506.9**

Source: AAI, p. 92, table 7.1and 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 around 70% of the remaining cast iron and unprotected steel mains on the network, to augment the network in line with the foreseen growth in demand and to maintain its 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. [32]

In addition, a comprehensive statement on movements in tendered rates has been presented and forms the foundation of the majority of the estimates. [33]

32 AAI, attachment 6.4 (*Real Cost Escalation*).

33 AAI, attachment 7.1 (*Capex and Unit Rates*).

The forecast costs have been split into categories as shown in the table above.

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 in the present period of the slow-down in mains replacement and the impact of its planned acceleration in the next period. They also highlight a "catch-up" in mains augmentation, including supplies to new areas of growth, and we discuss these factors 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 growth, inclusive of an element of real cost escalation.

Figure 4.1: Expenditure Trend ($2010 m)

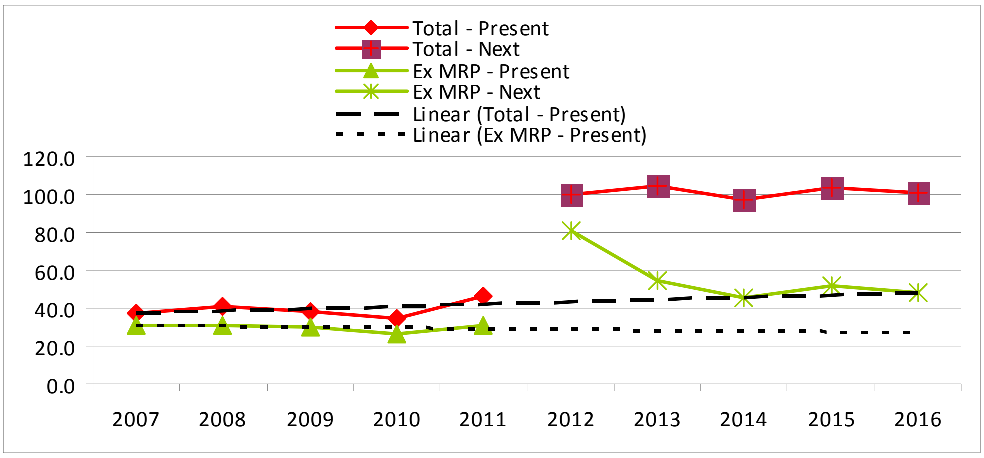
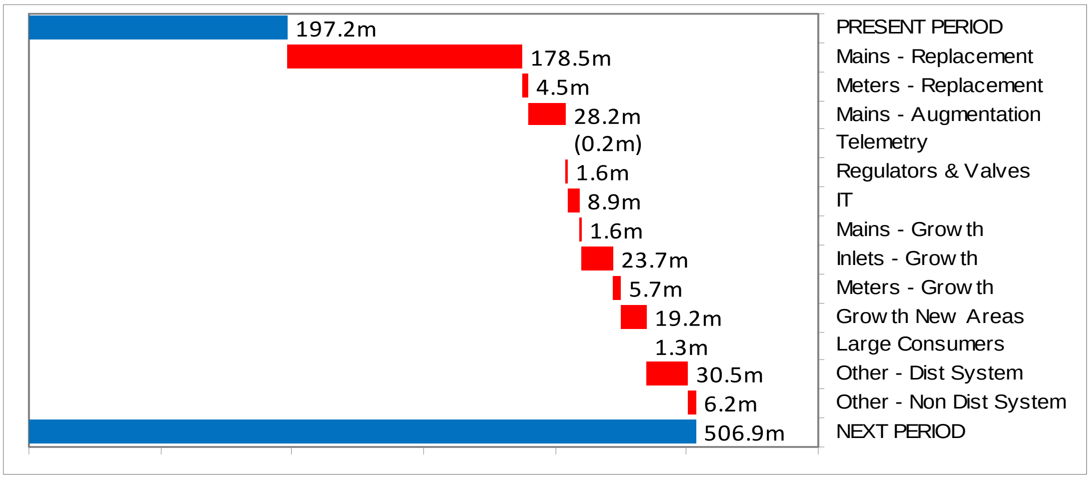


Figure 4.2 shows the contributions of changes in the various expenditure categories to the total increase from the present period and the next.

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 $178.5 m, followed by the growth categories (which, in total, are projected to be $51.5 m above the level in the present period), augmentation (an increase of $28.2 m), and the remaining categories (an increase of $51.5 m).

4.2 Mains Replacement Expenditure

Proposed Expenditure

The biggest expenditure category in the next period, by far, is the replacement of mains. Envestra proposes to spend $226.5 m on this work (accounting for 45% of capital expenditure in the next period), replacing about three-quarters of its then-remaining cast iron and unprotected steel mains in the Adelaide and Mt Gambier networks to reduce gas leakage, reduce repair costs, increase network capacity and reduce the risk inherent in the deteriorated state of these mains. [34]

A total of 1,072 km (of which 943 km or 88% is cast iron and unprotected steel) is to be replaced in the next period and a further 411 km is to be replaced in the following period. [35]

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: [36]

> It is planned to replace all remaining Low and Medium Pressure Cast Iron (CI) and Un-protected Steel (UPS) mains within the Adelaide and Mt Gambier Distribution Networks based on safety risk, inadequate capacity and deteriorating condition and integrity.
>
> In total, it is planned to replace 1,610 km of predominately LP mains over the next 7-8 years.
>
> The prime safety risk concern is associated with gas entering buildings, especially from a circumferential break in the CI network where a sudden large release of gas could have sufficient volume to create an explosive mixture in a nearby building. The risk is particularly acute within the CBD, though several smaller areas within the broader metropolitan area have also been identified as posing a risk. A Cast Iron Mains Fracture Model has been used to identify these high-risk areas, focussing on the Adelaide Metropolitan zone.
>
> Trends in key integrity performance indicators suggest that the CI & UPS mains are deteriorating faster than current replacement rates for these mains. In particular, UAFG has increased by an average of 5% per year over the last 5-6 years. It is currently estimated that leaks from CI & UPS mains account for 80% of the Adelaide and Mt Gambier network' UAFG, costing approximately $8 M per annum.
>
> Over the last few years, the impact of urban consolidation and the use of high instantaneous demand appliances has eroded the spare capacity within the LP Network. It has been determined that a significant amount (540 km) of the LP network in Adelaide, predominately consisting of CI & UPS mains, have inadequate capacity to service existing and new consumers under peak load conditions.
>
> The replacement and upgrade in pressure of these mains is considered to provide the most effective and efficient long term solution to this issue.
>
> The replacement of all CI & UPS within the Adelaide and Mt Gambier metropolitan areas (excluding the Adelaide CBD) is also economically prudent, with the cost of replacement offset by a number of benefits, principally reduced UAFG and leak repair costs.
>
> A strategic review of risk, performance and condition has concluded that all CI & UPS mains in the Adelaide and Mt Gambier metropolitan areas should be replaced as soon as practicable. Considering various design, tendering, contract negotiation and mobilisation issues, total replacement of the CI & UPS mains is planned over the next 7-8 years.
>
> The following table summarises the planned replacement programme.

	2010/11	2011/12-2015/16	2016/17-2018/19	Total
Replacement Length (km)	130	1,072	411	1,613
Cost (Direct) ($M)	15	187	64	266

> The mains replacement programme is expected to result in the following benefits:

34 Source: *Mains Replacement Plan,* p. 6.

35 A residual of 27 km is forecast to remain in service afterwards.

36 Attachment 7.4 to the AAI. We reproduce the executive summary in full.

> 1. Reduced risk of fire and explosion.
> 2. Reduced operational risk to maintenance personnel from sudden mains "blow-outs".
> 3. Increased network capacity, to meet existing and future customer requirements.
> 4. Reduction in the Adelaide distribution system UAFG by approximately 1.6 PJ.
> 5. Reduction in the Mt Gambier distribution system UAFG by approximately 0.034 PJ.
> 6. Reduction in maintenance costs associated with leak repair.
> 7. Reduction in pressure regulator maintenance costs.
> 8. Reduction in metering and billing errors associated with pressure correction factors.
> 9. Reduction of approximately 500,000 tonnes/year (equivalent CO_2) of greenhouse gas emissions.
>
> Replacement of mains will be prioritised on the basis of:
>
> 1. Risks associated with large volume gas release from fractured CI mains.
> 2. Maintaining adequate capacity to existing consumers.
> 3. Economic justification.

In support of this, Envestra states elsewhere in its *Mains Replacement Plan* that: [37]

- its network has experienced a 13% p.a. average linear increase in the rate of occurrence of cracks and breaks since 2004;
- the 5% p.a. increase on average in UAFG over the last 5 to 6 years has occurred in spite of an annual cast iron and unprotected steel mains replacement rate of 4% in the same period;
- UAFG is increasing at a faster rate (6%) in Mt Gambier; and
- overall, there was an increase of 18% in the rate of reporting by the public of leaks, during 2002 to 2009, an annual rate of increase of about 2.5% p.a.

Envestra has prepared economic analyses of the mains replacement investment for the Adelaide CBD, Adelaide metropolitan area and Mt Gambier network separately, 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 reported defects and (b) the present value of the estimated reductions in gas leakage (and some other benefits [38]) that would be achieved if the mains were replaced. Different rates of network deterioration are tested, as are different deadlines for completion of the replacement. 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 (pp. 44-45):

> Total replacement of the CI & UPS in the metropolitan area would return a positive NPV with an underlying UAFG escalation rate between 9% and 10%. Given that the underlying network deterioration rate, as derived in Section 4.4.8, may be as high as 12% the replacement of all CI and UPS mains is considered prudent even if the work is based solely on economic grounds…
>
> Replacement of the Adelaide CBD cannot be justified solely on economic grounds.
>
> The replacement of Adelaide CBD mains is justified based on safety/risk issues and maintaining system integrity…
>
> Total replacement of Mt Gambier can be justified on an NPV basis given that the expected remaining life of the UPS mains is unlikely to exceed 20 years.

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

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[37] From pp. 9, 15 and 16 of the Plan.

[38] Listed on p. 42 *et seq* of the *Mains Replacement Plan.*

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. [39]

Consideration is given to the need for increased capacity where required to meet existing and future customer loads. [40]

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. [41]

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 draft decision covering the present period, the ESCOSA noted that the business had proposed the replacement of around 500 km of predominantly cast iron and unprotected steel mains in the period at an average rate of around 100 km p.a. [42]

The Commission noted the view of the technical regulator, which had suggested that due to the apparent accelerating rate of deterioration of the remaining cast iron and unprotected steel mains, an even-further-accelerated programme of mains replacement might be desirable.

The Commission noted that its own advisers, Economic Consulting Group (ECG), had examined the mains replacement programme and concluded that its scope was reasonable.

In its draft and final decision, however – and whilst accepting the extent of the replacement programme – the Commission did not accept the unit rates proposed by the business and so reduced them when calculating its allowance. [43]

The Commission observed that Envestra had proposed a significant programme of mains replacement in the first access arrangement period but had reduced the rate of replacement from its planned level of around 200 km p.a. to around 50 km p.a. when UAFG fell more rapidly than anticipated in FY 2003.

As already mentioned, Envestra is expecting to complete 491 km of mains replacement in the present period. [44]

The Commission considered that that adjustment by the business essentially reflected an attempt by the business to optimise the replacement costs against the accompanying reduction in UAFG and leak repair costs and acknowledged – rightly, in our view – that it was not a legitimate objective to drive UAFG costs to zero at any price or words to that effect.

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39 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 low.

40 Reference to "existing" loads is to areas where the maximum operating pressure achievable is already marginal or inadequate, because of network constraints. Envestra's network analysis indicates that it has 540 km of mains in this category – see the *Mains Replacement Programme*, pp. 19-20.

41 We have noted already in this report (section 2.2) that raising the operating pressure of cast iron pipelines (and thus their capacity) is generally not possible.

42 *Proposed Revisions to the Access Arrangement for the South Australian Distribution System - Draft Decision*, ESCOSA, p. 116.

43 In commenting on our draft report, the AER noted that the ESCOSA's allowance for capital expenditure in the present period was nevertheless a 70% increase in real terms on the level approved in the preceding period.

44 We have already noted that the reported costs in the present period suggest a replacement cost per kilometre that is more in line with the business's own estimates than the reduced rate approved by the ESCOSA. See section 3.3.

View of Technical Regulator

We note that the technical regulator observed in its 2008-09 annual report:

> "[The Office] has again expressed and reiterated to Envestra that past and current levels of UAFG, despite the ongoing mains replacement (approximately, 47 km of cast iron mains were replaced in 2008-09, instead of approximately 100 km, indicated by Envestra under the Second Access Arrangement approved by the ESCOSA in 2006), could strongly suggest that the remaining cast iron and unprotected steel mains are deteriorating at an accelerating rate. This may have a consequential negative impact on the safety and reliable performance of the Envestra distribution networks. This could also suggest that the current rate of mains replacement may need to be reviewed by Envestra, as matter of urgency".

Practicality of ESCOSA's Proposed Target

Although UAFG is an issue for all gas distribution systems from a safety and economic perspective, it has apparently been of particular concern to the ESCOSA because of the high levels of losses that continue to be reported. [45]

ESCOSA and the technical regulator continue to express concern about UAFG and that the latter has recommended that Envestra review the current and future rate of mains replacement to reduce gas losses as soon as practicable and that there should be an annual UAFG target "imposed" on Envestra.

We further understand that, in response to these concerns, the ESCOSA determined in September this year to amend the Gas Distribution Code by the insertion of a new clause imposing a "best endeavours" UAFG target for South Australia of 4% by FY 2016 and a "best endeavours" obligation to achieve annual reductions in UAFG levels during the period. However, for reasons that we discuss, we are not convinced that the proposed target is practical.

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 meetings.

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

We further noted the observations of the technical regulator, as summarised above. However, we did not feel bound by those observations as the ambit of the Office is presumably to do principally (if not entirely) with public safety, service levels and reliability, whereas we are to consider the proposed expenditure from the standpoint of prudence and efficiency. [46] Of course, we do not imply by this that matters of safety or reliability ought to be ignored.

We further noted the UAFG target of 4% just proposed by the ESCOSA as stated above but it is not clear to us that the proposed target is practical.

We agree with the view expressed by the ESCOSA (at the time of the previous review) that it is not a legitimate objective to drive UAFG costs to zero at any price, or words to that effect.

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[45] The level of UAFG reported by Envestra for FY 2011 is projected to be around 2.2 PJ p.a. or 8.3% of gas input excluding deliveries to "farm taps".

[46] The Office may also have an interest in environmental costs or economic costs to the country as a whole but the AER is the jurisdictional economic regulator of the business.

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.

(a) At the risk of stating the obvious, pipelines such as those under consideration do not last forever and their replacement at some time is inevitable 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, if efficiency is to be achieved in the costs of replacement, then 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 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 and we noted that, to date, no determination of the economic or technical regulators concerned had reached a contrary conclusion in relation to need.

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 considered 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) 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 scenario evaluated. We admit, however, that that may achieve much the same result.

(c) 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.

(d) 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.

(e) 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 replacement programme are substantial.

Overall, we concluded the analyses support the business's decision to proceed, in addition to which the quantified analysis so prepared is only one leg of the case: the non-quantified risk assessment and the need in some locations to increase network capacity are equally valid (although subjective) – and neither of those benefits was included in the quantitative analyses.

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.

We asked the business to explain how it proposed to deal with this issue (and the extent, for example, that targeted replacement mains areas coincide with areas of poor pressure). In response, we were informed that low pressure was not the most important driver of the replacement work as, generally, older low-pressure mains were in established areas with low load growth. [47]

Envestra further stated that replacements in Mt Gambier are driven principally by safety issues and that the possibility of a catastrophic incident in metropolitan Adelaide was real, as evidenced by a gas explosion in a residential suburb in recent years.

Reduction in Gas Leakage

Envestra's assessment is that 80% of gas leakage is attributable to the mains that need to be replaced and we considered that reasonable.

We examined the UAFG rates reported by the business and concurred there is evidence that the network is deteriorating on this measure. However, we consider that there is doubt about the rate at which this will occur in the future. The *Mains Replacement Program* states (p. 9),

> The moving annual total UAFG for the Adelaide metropolitan network has been increasing, on average, by at least 5% per year over the last 5-6 years despite an annual CI & UPS replacement rate of 4% during this period…UAFG increases in Mt Gambier have been averaging 6% per year over the last five years.

This implies a rate of deterioration (and thus of increased leakage) of 9.48% p.a. (1.05 x 100/96 -1). However, the leak report charts in the *Mains Replacement Plan* were not considered by us to support the contention of an increasing **rate** of leakage as asserted by Envestra, although that may be the case or could become the case over time. [48]

Envestra has concluded a 9% rate of deterioration will continue (whether compound or linear makes little difference in the short term) but we are not able to reconcile its volumetric estimates of UAFG with this estimate, as we explain below.

We note further that the business reacted to the effects on UAFG of mains replacement work as it proceeded in the present period, modifying the rate of replacement accordingly, and we consider that a valid response as it is optimality of leakage *vs.* replacement cost that should be sought, not leakage reduction for its own sake.

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47 Answers of 18 November to our question (AR's reference WC.EN.12-16). Envestra also noted in its reply that infill housing or new housing development is likely in some areas, although that is likely to occur mainly after the mains have been replaced.

48 The chart on p. 16 of the *Mains Replacement Plan* is stated as showing an increasing trend in surveyed leak reports but we note that the number of leak reports in 2008 and 2009 is less than in 2005, 2006 and 2007 and is consistent with the number in 2004. This does not appear to indicate an increasing trend in the reported number of leaks. The public reported leaks charted on p.15 do not necessarily confirm an increasing trend either, by that measure.

Prioritisation of the Work

We were satisfied that the proposed method of prioritisation of the work is sound, noting that it would emphasise high-risk areas or areas where other benefits could be realised (e.g. added capacity to supply new or increased customer loads) or both.

However, as already noted, as a matter of practicality the work will need to be carried out area by area, not piecemeal, and that the network contains many areas where replacement could be considered a high priority. Therefore, in spite of the business's best endeavours, we consider it unlikely that the work could address solely the areas of greatest leakage first, although we do consider that there ought to be some favourable impact on the average rate of leakage from the remaining pipelines as the work proceeds.

Timing

We reviewed the proposed timing of the expenditure, noting that 113 km of replacement is scheduled for each of the years FY 2011 and FY 2012 and 233 km in each following year in the period. We considered that the business had allowed sufficient time to marshal the resources needed and that it has achieved substantial rates of progress in the past.

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 $211 per metre in FY 2010 dollars ($226.5 m divided by 1,072 km) and that this rate is considerably above the rate achieved in the present period of $98 per metre in FY 2010 dollars ($48 m in divided by 491 km). However, caution is needed before drawing any conclusions from this comparison as the work in the present period was not undertaken in the CBD (whereas much of the planned work in the next period is to be), 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 Estimate

We have already indicated in this section of the report that we consider the proposed volume of mains replacement reasonable. Therefore, subject to the removal of contingency allowances, the reasonable application of real cost escalators and the reasonable apportionment of capitalised indirect costs (all of which we discuss in section 4.7 of the report), we consider the expenditure estimate is reasonable for the work proposed.

Significant Reduction in Operating Expenditure

A related point not to be overlooked is that Envestra has proposed significant reductions in its operating expenditure because of the proposed investment in mains replacement and those reductions will not be available if the programme is deferred and would be reduced if it were delayed.

Estimated Level of UAFG in Next Period

Although we have concluded above that the expenditure estimate is reasonable for the work proposed, several related matters concern us. The first of these is the level of reduction in UAFG that has been forecast by Envestra.

We have already noted that we are not able to reconcile Envestra's volumetric estimates of UAFG with the proposed rate of replacement of the mains. In essence, we are not satisfied that the projected level of reduction in UAFG is adequate. Table 4.2 summarises our concern.

The table shows that under Envestra's projection, losses will be reduced only from 8.3% to 7.1% over the period. This percentage calculation is affected by the declining level of sales, of course, and that is why we have carried out our analysis in terms of energy (TJ), not in percentages. Nevertheless, the conclusion to be drawn is that the projected level of loss reduction, as presented by Envestra, is minimal.

We attribute this to an assumed high rate of deterioration on the mains still in service each year and our modelling shows this to be the case.

The question, therefore, is; what annual rate of deterioration (and increased leakage) ought to be assumed for mains that remain in service in the next period, awaiting replacement. We have already questioned the rate of deterioration of 9% p.a. assumed by Envestra and further note that it is equivalent to just under a 50% increase in leakage rates over the period. We find it hard to believe that such a rate of increase will be sustained over the period, although the possibility exists.

We further note that the number of leak repairs is projected by Envestra to fall by 60% over the next period. The minimal reduction in losses forecast by Envestra does not appear to be in alignment with that projection.

Table 4.2: Analysis of Forecast Level of UAFG

FY	2011	2012	2013	2014	2015	2016	
Envestra's Projections							
Forecast Sales a/	23,874	23,879	23,061	21,767	21,327	21,297	
Mains Replaced (km)	-	140	233	233	233	233	
Forecast UAFG (TJ) b/	**[C-I-C]**	**[C-I-C]**	**[C-I-C]**	**[C-I-C]**	**[C-I-C]**	**[C-I-C]**	
UAFG (Pct of Gas Input)	**[C-I-C]**	**[C-I-C]**	**[C-I-C]**	**[C-I-C]**	**[C-I-C]**	**[C-I-C]**	
Our Analysis	**Start**					**End**	**Final**
A: Length to be replaced in next period	1,072	932	699	466	233	-	-
Replaced	-	140	373	606	839	1,072	1,072
B: Length remaining to be replaced later	411	411	411	411	411	411	-
Replaced	-	-	-	-	-	-	411
Losses due to A (TJ)	1,257	1,195	973	700	376	-	-
Losses in New Pipework (A) c/	-	4	10	16	23	29	29
Losses due to B (TJ) d/	482	527	572	617	662	708	-
Losses in New Pipework (B) c/	-	-	-	-	-	-	11
Other Sources of UAFG (TJ) e/	435	435	435	435	435	435	435
Total UAFG (TJ) f/	2,173	2,160	1,990	1,768	1,495	1,171	475
Pct of Gas Input	8.3%	8.3%	7.9%	7.5%	6.6%	5.2%	2.2%
Avge Annual UAFG (TJ) (9.4% Det.)	2,173	2,167	2,075	1,879	1,632	1,333	475
Pct of Gas Input	8.3%	8.3%	8.3%	7.9%	7.1%	5.9%	2.2%
Avge Annual UAFG (TJ) (0% Det.)	2,173	2,093	1,879	1,612	1,346	1,079	475
Pct of Gas Input	8.3%	8.1%	7.5%	6.9%	5.9%	4.8%	2.2%
Recommended Level of UAFG (TJ)	**2,173**	**2,130**	**1,977**	**1,746**	**1,489**	**1,206**	**475**
Pct of Gas Input	**8.3%**	**8.2%**	**7.9%**	**7.4%**	**6.5%**	**5.4%**	**2.2%**

a/ Sources: p. 74 of attachment 13.1 to the AAI (NIEIR forecast of sales) and pp. 56-7 of attachment 7.4 to the AAI (Mains Replacement Plan). Other documents for remaining information. Excludes farm taps.
b/ FY 2011 figure from the source document adjusted to include Mt Gambier.
c/ Assumed leakage per km p.a. in new mains of: 0.027 TJ
d/ Assumes linear rate of increase in leakage of 9% p.a. until replacement.
e/ Losses from other pipelines and network elements and from other sources of UAFG, e.g. operations, metering errors, conversion inaccuracies, etc. Assume no change.
f/ End-of-year figures.

Therefore, as shown in the table, we first calculated the losses using Envestra's assumed rate of deterioration in the remaining pipes (actually, we assume a rate of 9.48% as calculated earlier in this section of the report in place of Envestra's assumption of 9%). [49] On that assumption, we project a reduction in UAFG over the period in percentage terms from 8.3% to 5.9% as shown in the table.

We then re-calculated the reduction in UAFG, assuming a nil deterioration rate (rate of increase in leakage) and those figures are shown in the table as well.

On balance, given the doubt that we retain about future leakage rates, and in the absence of better information, we then took a mid-point between these upper and lower bounds and present the resulting scenario in the final (highlighted) line in the table as our estimate of the level of UAFG in the next period if the work proceeds as planned by Envestra.

The resulting reduction in UAFG over the period, expressed in percentage terms, is from 8.3% to 5.4% – or, expressing it more correctly, from 2,130 TJ in FY 2012 to 1,206 TJ in FY 2016, as shown in the table.

Mains Remaining in Service

We note that 27 km of cast iron or steel mains are said to remain after the conclusion of the programme in the next period. Leakage from it is not included as presumably it is insufficient to warrant replacement.

Commercial Considerations

Having reached the conclusions just stated (in relation to the reasonableness of the expenditure and a matching level of UAFG), we note that the business may react to the effects on UAFG of mains replacement work as it proceeds by modifying the rate of replacement accordingly and we consider that this would be a valid response, as it is optimality of the cost of leakage *vs.* mains replacement cost that should be sought, not leakage reduction for its own sake.

We suggest to the AER that this possibility be considered in its decision.

Conclusion

After considering these factors, we conclude that the mains replacement programme is prudent and efficient. However, we consider that the resulting level of reduction in UAFG has been under-estimated by the business and we further consider that a more appropriate level of reduction would be from 2,130 TJ in FY 2012 to 1,206 TJ in FY 2016, as shown in Table 4.2.

We further consider (based on this analysis) that the ESCOSA's proposed target for UAFG reduction is unrealistic and ought to be modified.

4.3 Growth-Related Expenditure

The second-largest expenditure category in the next period is growth-related expenditure on mains, inlets (*viz.* service connections to customers), meters, connections to new areas and connections to large customers. Envestra proposes to spend $157.1 m on these items in the next period compared to $107.9 m in the present period. [50]

Expenditure under this category accounts for 31% of the proposed capital expenditure in the next period.

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[49] Whether the rate is compounded or linear makes little difference – only about 0.2% in the last year of the period.

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

Envestra 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 extensions of the network to three new areas and the forecast cost of new or upgraded connections to large customers.

Mains, Service Connections and Meters

The forecast growth-related expenditure on mains, service connections and meters is $135.9 m, of which $31.6 m is attributable to mains, $79.1 m to services and $25.2 m to meters. An outline of the work proposed is given in section 7.6.7 of the AAI.

Envestra states that it has estimated the average length of main (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 mains required to serve demand customers on the forecast demand and it has forecast the number of new connections.

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 Envestra, the mains component in the case of volume customers is calculated by dividing the total historical length of main 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 7 to 10 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 make up the remainder of the expenditure. We understand that their cost includes the cost of the meter itself, 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. We did not attempt to verify the calculations for demand customers, given their special nature.

We discuss the unit rates further in section 4.6 of this report and in subsequent sections.

Significant Extensions (Growth in New Areas)

The forecast expenditure on significant extensions (growth in new areas) $19.2 m, most of which occurs in the period FY 2012 – FY 2013. The areas involved are Tanunda, McLaren Vale and Buckland Park and an outline of the work proposed is given in section 7.6.7 of the AAI and in business cases S25, S56 and S55 respectively.

According to the business cases, none of these areas is supplied with reticulated gas at present. Based on studies and demand projections carried out, Envestra is of the opinion that sufficient demand exists or is expected to develop during the next period to justify a supply to each area and reticulation. The business studies indicate a positive return on the investment.

We have reviewed the cost estimates provided in these business cases and consider that the unit rates used to estimate reticulation and customer connection costs are within the expected range. No specific information was provided in the business cases on how the unit rates used for the supply mains to each area were calculated but we considered it reasonable to assume that those rates were fixed in accordance with attachment 7.1 to the AAI. We discuss that attachment in section 4.6 of this report.

New or Upgraded Connections to Large Customers

Connections to large customers, i.e. industrial customers with annual consumption greater than 10 TJ p.a., are projected to account for $2 m of expenditure in the next period. The work includes work in relation to new customers and to existing customers requiring an additional capacity. [51]

The demand forecast estimates that there will be a total of seven such new customers and Envestra estimates that two such existing customers will require an upgraded supply each year in the next period. Envestra has allowed a unit rate of $150,000 per new customer and $100,000 per upgrading, based on "historical spend assessment and experience with demand connection". [52]

We did not attempt to verify these costs because of their special nature but note that the total expenditure involved is immaterial.

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). We discuss the cost-efficiency of the work further in section 4.6 and subsequent sections.

4.4 Mains Augmentation Expenditure

Envestra proposes to spend $29.3 m on mains augmentation in the next period. Expenditure under this category accounts for 6% 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 to identify and evaluate augmentation projects are set out in attachment 7.3 to the AAI, the *Capacity Management Plan* and we reviewed those processes.

We discussed the projects with Envestra's staff and reviewed the business cases for the nine 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,

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51 See the AAI, attachment 7.1, p. 10.

52 *Ibid.*

pressures in parts of the network will drop below an acceptable level), the options considered and the cost-benefit analysis. [53]

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 20% contingency allowance included in these estimates.

Only in one case (the Greenhill Road project) is any justification for the contingency provided (Business Case S29). There, it is stated,

> This contingency is to account for the fact that a FEED study has not been undertaken to identify constraints associated with other below ground utilities and road authority permissions/restrictions which may affect route selection and reinstatement. In addition, there has been significant volatility in contractor rates received for similar projects. More accurate costing will not be possible until a FEED study has been completed and a firm scope of work tendered.

Although a specific purpose such as this might warrant a provision to deal with an expected cost that cannot be quantified at present, the resulting application, in this example, of a factor of 20% to the estimated direct cost of $9.1 m (AAI, p. 103) results in a provision that appears excessive for the work involved.

4.5 Other Expenditure

The remaining expenditure in the next period amounts to $93.9 m or 19% of the total forecast capital expenditure in the period. It is made up of meter replacements ($21.0 m), telemetry ($2.3 m), regulators ($4.1 m), IT systems ($10.9 m), "other" distribution system expenditure ($48.7 m, of which around $30 m is said to be accounted-for by new standards for road reinstatement) and "other" non-distribution system expenditure ($6.9 m).

Meter Replacements

The proposed expenditure of $21.0 m on meter replacements is summarised on pp. 101 and 102 of the AAI. It is comprised of three items: domestic meters ($15.2 m) and industrial and commercial meters ($2.5 m) and industrial and commercial refurbishment ($3.3 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) authorised by the Technical Regulator. This continuous changeover and testing program ensures that each gas meter continues to operate within prescribed tolerances. The obligations and associated processes are set out in Envestra's Gas Measurement Management Plan, which is submitted annually to the Technical Regulator for approval."

Envestra's *Gas Measurement Management Plan* (a document required by the South Australian *Gas Metering Code* and in respect of which compliance is required as a licence condition) addresses, *inter alia*, meter accuracy, meter replacement policies and meter maintenance practice. A meter-testing regime is set out in the code and a meter changeover programme is carried out in accordance with its requirements. The *Asset Management Plan* provides an inventory of domestic meters by age and we reviewed the forecast numbers of meters to be changed or refurbished against the inventory and considered that there was a

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53 A cost-benefit analysis was not provided for the ad-hoc 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.

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

An inventory is not provided for industrial and commercial meters (which are relatively few in number) but Business Case S05 indicates around 9,000 such units in service. [54] We note that the forecast number to be replaced or refurbished in the next period is approximately 4,300 or just under 50%; and, given a 10-year testing interval, this appeared reasonable. 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 refurbish 1,400 meter sets, including grit blasting, re-coating and the fitting of additional valves. Justification for this work is set out in Business Case S05. It includes life extension and, in some cases, safety.

We consider the expenditure reasonable, subject to the removal of the 10% contingency allowance.

Telemetry

The forecast expenditure of $2.3 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 $4.1 m on regulators and valves is not material either but we did note that it is composed of around $3.2 m for critical regulator vault replacements and $1.5m for the refurbishment of critical valves. [55]

According to Envestra, the condition of (and limited access to) 26 underground regulator stations warrants their replacement. The proposed work includes new regulators and pipework installed in new chambers with good access. Envestra states that 253 isolation valves located in underground pits in Adelaide are corroded and may become inoperable if remedial work is not carried out. The proposed work involves *in-situ* treatment.

We considered both items justified. However, we considered that the refurbishment of the valves was maintenance and therefore ought to be expensed, rather be than added to the regulatory asset base. An adjustment is recommended accordingly, as is a commensurate increase in operating expenditure.

IT Systems

The forecast expenditure of $10.9 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 on the need for the resulting benefits to be considered in the operating expenditure projections.

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[54] Business Case SO5 (*IC Meter Set Refurbishment Capex)*, p. 2.

[55] The amounts are approximate, as the detailed estimates in business cases S13 and S14 for these works add to slightly more than the figure for the combined item in the AAI.

"Other" Distribution System Expenditure

Change in Standards for Reinstatement of Major Roads

Around $30 m or 60% of the forecast expenditure of $48.7 m under this heading is said to be due to the impact of new standards for road reinstatement introduced with effect from 1 July 2010.

According to Envestra, the additional costs that will be incurred have "already been factored into the forecast" for mains replacement but, by implication, not for other capital in operating expenditure. [56] The proposed capex allocated to this work totals $30 m, spread evenly over the period. [57]

Envestra states as follows in its business case for this work (case S52):

> The introduction of the new standards for DTEI [58] road reinstatements will have an immediate impact from 1st July 2010 on the cost of a significant proportion of the Capital Works including, Mains Alterations, Mains Replacement, Major Projects, Growth Mains, New Services, and will also impact Leak Repair costs. SA Networks performs Capital Works using a combination of directly employed field crews and contract crews operating under a range of commercial agreements. These agreements are either project based or fixed term contracts depending on the work type. Contractors performing this work who are operating under an existing services agreement will be entitled to claim for the additional expenses incurred. Similarly, all tendered or quoted works will continue to include the total scope of the job including service and main laying, reinstatements, as laid drawings, documentation, equipment and consumables, and will therefore attract a higher premium to include costs associated with the imposed higher standards for road replacement and repair.
>
> Actual costs will depend on the number of projects, services and remedial work conducted in DTEI roads and could vary from year to year.
>
> It is expected that the foreseeable volumes of reinstatement work will be similar to recent experience, and if anything, may increase due to the ageing of existing gas infrastructure. Local councils have traditionally adopted and enforced DTEI specifications following their introduction, and it is highly likely the more onerous standards will be adopted progressively throughout the Adelaide metropolitan area. Envestra therefore believes that its forecast is very conservative at the bottom end of the range of reasonable projections.

Our understanding, based on this statement, is that the unit rates used in the preparation of Envestra's capital forecast for the next period capex were based on reinstatement standards applying **before** 1 July 2010, with the exception of mains replacement.

Envestra provides a table in its business case that shows the proportion of future works comprising new services, new mains and extension projects to which the additional costs are said to relate. However, we have no means of verifying it.

According to Envestra, a rate of $**[c-i-c]** per square metre of surface area involved was established in consultation with two DTEI-approved contractors as the incremental cost resulting from the new standards. However, we also note that a rate of $160 per square metre is used in the table in the business case for surface reinstatement but that no explanation is given for the difference in these figures.

A further doubt arose as the work to which the new surface reinstatement requirements apply could include augmentation projects, the cost of which has been determined without reference to unit rates. There may therefore be a degree of double counting in the estimates.

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56 AAI page 109.

57 The amounts are, as the detailed estimates in business cases S52 are expressed prior to the application of overheads, real cost escalation and contingencies.

58 The Department for Transport, Energy and Infrastructure.

In addition, we note that the estimates assume a double-lane road crossing for services, but not all services will require that.

Whilst recognising that the work appears necessary, we consider that the amount agreed in respect of it ought to be reduced unless the business is able to satisfy the AER in relation to the points we have raised.

In the absence of sufficient information, we propose an allowance equal to half the amount proposed by Envestra.

Remaining Items in this Expenditure Category

The remaining nine small expenditure items in the category "other distribution system expenditure" total around $18.5 m and have been proposed by Envestra to maintain network integrity. They are listed and discussed on pp. 108 and 109 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 non-compliant regulators identified by a survey ;
(c) the replacement of service connections (inlets) that are determined by survey to be hazardous;
(d) the replacement of pipes laid in sleeves under railways;
(e) the fitting of automatic fire shut-off valves to service connections in potential bush-fire areas;
(f) the fitting of covers on "long bolt" flanges for fire protection;
(g) minor repairs on the transmission-pressure network following "approved engineering investigations".
(h) the removal of gas contaminants from pipelines; and
(i) connection compliance reporting, a mandatory item.

Details of the work, including justifications and cost estimates, are provided in various business cases. [59]

Of these, the replacement of hazardous service connections accounts for around $7.8 m and the work on "sleeved" railway crossings accounts for around $4.6 m, the remaining items (totalling $6.1 m) being immaterial individually and in total. We reviewed all items and considered them prudent but comment further on the following.

Replacement of Hazardous Services (Inlets)

According to Envestra, the need for this project has arisen from a previous practice of installing service pipes in cavities in the walls of houses. Owing to some incidences of gas leaks resulting in concern on the part of the technical regulator, Envestra considers that the pipes should be removed (Business Case S06). It estimates that there are approximately 1,900 installations involved.

The work appears prudent and the cost reasonable except that the 20% contingency allowance ought to be removed.

AEI Remedial Work

We consider that this work (Business Case S40) is maintenance in nature and ought to be expensed ($0.15 m) and not added to the regulatory asset base. A commensurate increase in operating expenditure should be allowed.

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[59] Work on odorising stations is listed in the AAI, p. 108 along with the items listed above but no expenditure is proposed under that category in the next period.

Sleeved Railway Crossings

A 20% contingency allowance added to the estimate for this item ((Business Case S18) should be removed.

"Other" Non-Distribution System Expenditure

Forecast expenditure of $6.9 m is proposed under the heading "other non-distribution system expenditure". The AAI (p. 110) identifies it as comprising the replacement of non-system plant and equipment ($2.2 m), development of interactive computer-based training ($0.8 m), purchase of replacement trucks ($1.6 m) and new equipment to support additional crews to be employed over the next period ($0.9 m). [60] The projects are described and justified in Business Cases S19, S44, S46 and S48. We considered that the expenditure appeared prudent and noted that allowances for contingencies did not appear to have been added.

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, a well-written document of 15 pages, discusses the make-up of the costs applied to work under the following headings: mains in new estates, mains to existing homes, mains to industrial and commercial premises, service connections (inlets) to new homes, service connections (inlets) to multi-user sites, service connections (inlets) to existing homes, service connections (inlets to industrial and commercial premises, the periodic-meter-change programme for domestic meters, the same for industrial, commercial and demand customers, domestic meter connections, industrial and commercial meter connections, connections for large consumers and, finally, mains replacement of various types (block replacement, trunk replacement, CBD block replacement and CBD trunk replacement). [61]

We refer you to the attachment in full, as it is a comprehensive statement of the basis of the various cost estimates and their efficiency. It is clear from the statement 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 by Envestra in the spreadsheet in attachment 7.5 to the AAI.

We consider the resulting unit costs efficient based on the analysis as presented and comparisons with such other information as is available to us, subject to removal of the following general contingency allowances noted in the attachment: block and trunk mains replacement, 10%, and block and trunk mains replacement in CBDs and piecemeal mains replacement, 20%.

We did not establish the existence of contingency allowances in any other business plans other than those in relation to augmentation, valve refurbishing and "other distribution capex". We were not able to ascertain whether contingencies are included in the IT project estimates.

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 contingencies other than as stated above.

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60 The costs indicated are taken from the business cases and exclude escalators or capitalised overheads.

61 Reference to "block" mains replacement is to the replacement of an area.

4.7 Contingencies, Escalation and Indirect Costs

Contingencies

Envestra has added contingency allowances to some of its unit rates for mains replacement and to its cost estimates for augmentation projects, as already noted earlier in this report. In its AAI (p. 95), it states:

> In accordance with best practice, projects have been allocated contingency to account for uncertainties in project scope or execution.
>
> The amount of contingency determined is consistent with a matrix based on the "AACE (Association for the Advancement of Cost Engineering) International Recommended Practice 17R-97 –Cost Estimate Classification System TCM Framework 7.3 – Cost Estimating and Budgeting", with the majority of projects requiring a 10-20% contingency.

The rates, inclusive of the contingency allowances, are used in the calculation of the direct costs in the *Mains Replacement Plan* and in turn flow through to the capital expenditure model, where real cost escalation and capitalised overheads are applied, then into the RIN.

The business cases for network augmentation projects each include a 20% contingency applied as a general allowance, as opposed to a provisional sum in relation to a specific item.

Whilst it is normal to add a contingency allowance to estimates that are put to a board of directors for approval for expenditure, 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. [62]

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 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, as it has not been established that it is necessary.

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.

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

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. 89 *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; 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. [63] 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.

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, in at least some cases (e.g. the rates for mains replacement), overheads (e.g. incremental project management and planning costs) are added to the base costs (along with the contingency allowances) 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 so, there ought to be a reduction in the rates of application proposed.

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.

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[63] AAI, pp. 110-111.

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 identified.

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 at our meetings.

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 in these respects.

As a result, we have been able to conclude 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 4.3.

Table 4.3: Recommended Level of Capital Expenditure in Next Period ($2010 m)

FY ->	2012	2013	2014	2015	2016	Total
Envestra's proposal	100.3	104.7	97.3	104.0	100.6	506.9
Less recommended reductions						
Removal of contingency allowances:						
Mains replacement (15% average)	2.6	6.5	6.7	6.8	6.9	29.5
Meter replacement (10%)	0.3	0.3	0.4	0.5	0.5	1.9
Augmentation projects (20%)	2.7	1.0	0.2	0.9	0.0	4.9
Hazardous service inlets (20%)	0.3	0.3	0.3	0.3	0.3	1.3
Sleeved railway crossings (20%)	0.2	0.2	0.2	0.2	0.2	0.8
Items not fully substantiated:						
Main road surface reinstatement (halved)	3.0	3.0	3.0	3.0	3.0	15.0
Items that should be expensed:						
Refurbishment of valves	0.3	0.3	0.3	0.3	0.3	1.5
Repairs following AEI reviews	0.03	0.03	0.03	0.03	0.03	0.15
Recommended level of capex a/	91.0	93.1	86.2	92.0	89.4	451.8

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

The adjustment shown in relation to the mains replacement contingency allowance is an estimate, as the rate applied by the business differs in CBD and non-CBD areas. The adjustments shown in relation the remaining items other than replacement and augmentation are also estimated, as cost details were available only in relation to direct costs. In neither case were we able 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 if our recommended adjustments are adopted by the AER.

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.

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 6 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)

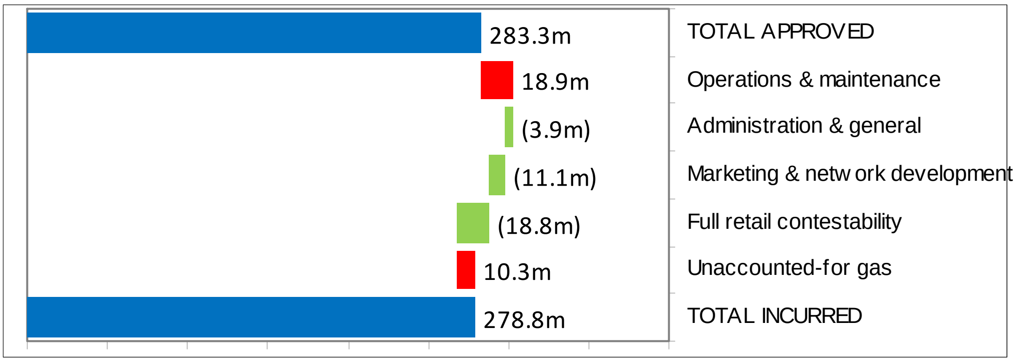
		FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	**Total**
Operating & maintenance	Approved	27.2	27.6	26.9	26.7	26.2	**134.6**
	Incurred	30.6	29.5	33.6	29.7	30.1	**153.5**
	Variance	3.4	2.0	6.6	3.1	3.8	**18.9**
Administration & general	Approved	7.4	7.7	8.4	8.7	8.8	**41.1**
	Incurred	4.7	8.1	7.7	8.3	8.4	**37.2**
	Variance	(2.7)	.4	(.7)	(.4)	(.4)	**(3.9)**
Network development & marketing	Approved	6.7	6.7	6.8	6.8	6.9	**33.8**
	Incurred	6.2	3.7	1.2	5.1	6.5	**22.7**
	Variance	(.5)	(3.0)	(5.6)	(1.7)	(.4)	**(11.1)**
FRC operating costs	Approved	6.5	6.8	6.8	7.0	7.0	**34.1**
	Incurred	4.7	3.9	2.3	2.2	2.2	**15.2**
	Variance	(1.8)	(3.0)	(4.5)	(4.8)	(4.8)	**(18.8)**
Unaccounted-for gas	Approved	8.1	8.0	8.0	7.9	7.8	**39.8**
	Incurred	8.1	10.6	10.6	10.4	10.4	**50.1**
	Variance	.0	2.5	2.6	2.5	2.6	**10.3**
Total	**Approved**	**55.9**	**56.8**	**56.8**	**57.1**	**56.7**	**283.3**
	Incurred	**54.3**	**55.7**	**55.3**	**55.8**	**57.6**	**278.8**
	Variance	**(1.6)**	**(1.1)**	**(1.4)**	**(1.3)**	**.9**	**(4.6)**
	Variance (%)	**-3%**	**-2%**	**-3%**	**-2%**	**2%**	**-2%**
Total excl. network dev & marketing and UAFG	Approved	41.1	42.1	42.1	42.4	42.0	**209.7**
	Incurred	40.0	41.5	43.5	40.2	40.7	**206.0**
	Variance	(1.1)	(.6)	1.5	(2.2)	(1.3)	**(3.8)**
	Variance (%)	-3%	-1%	3%	-5%	-3%	**-2%**

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 $278.8 m, $4.6 m (1.6%) below the $283.3 m approved for the period by the ESCOSA. Figure 5.1 shows the variances by expenditure category, highlighting the fact that although total expenditure is projected to be similar to that approved, there are significant variances in some categories.

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



Operating and Maintenance

The main variance is in operating and maintenance expenditure. Envestra expects to spend $18.9m (14%) more on this item in the present period than was approved by the ESCOSA. Envestra states that the increase is due mainly to increased leak repair costs. [64] Leaks accelerated at a rate higher than anticipated following the deferral within the period of an increased mains replacement programme. [65]

Full Retail Contestability

The second largest variance is in the costs associated with the introduction of full retail contestability (FRC). Envestra expects to spend $18.9m (56%) less on this item in the present period than was approved. Expenditure dropped significantly in the first 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. [66]

Network Development and Marketing

The third largest variance is in network development and marketing expenditure. Envestra expects to spend $11.1m (33%) less on this item in the present period than was approved. It states that the under-expenditure in network development costs is due to cost cutting in response to the global financial crisis, when a conscious decision was made virtually to cease, albeit temporarily, its development and marketing activities. [67] They were seen as being two of the few operating costs that could be curtailed at the business's discretion without adversely affecting the safety or delivery of its distribution services in a material way.

Expenditure is to be reinstated close to the approved level by the end of the period as the business considers that marketing must be resumed, not only to restore further gas penetration in the market but also to stem the present decline in the average daily consumption of gas per customer. [68] We consider the reduction was an appropriate commercial response to the financial restrictions on the business but agree that this will affect customer growth if not re-instated

64 AAI, p.32.

65 The mains replacement work proposed for the period is expected to be substantially complete by its end but augmentation expenditure was deferred.

66 AAI, p.34.

67 AAI, p.34.

68 AAI, p.34.

Unaccounted-for Gas

The fourth largest variance in total operating expenditure is in the cost of UAFG. Envestra expects to spend $10.3m (26%) more on replacement gas in the present period than was approved. It states that this cost has risen, particularly over the last two years, due to the increased deterioration of its mains, with leakage increasing at a rate that was not anticipated at the time of the last regulatory review. [69] Leakage from old cast iron and unprotected steel mains is considered the largest component of UAFG. As with the operating and maintenance expenditure which increased with the deferral within the period of the mains replacement programme, so there would have been a flow-on effect in terms of increased UAFG in volumetric terms.

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

Administration and General

A small variance in administration and general expenses accounts for the remainder of the variance. Envestra expects to spend $3.9m (9%) less on administration and general costs in the present period than was approved. Most of the variance occurred in the first year of the period: expenditure for the final three years is forecast to be similar to the allowance.

5.3 Conclusion

We discussed the expenditure during our meetings 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 operating expenditure carefully, making reductions in discretionary items to offset increases in non-discretionary operating expenditure that arose from deferral within the period of replacement capital expenditure. This was a reasonable and appropriate response in a period when external factors (particularly the global financial crisis) put the business under financial pressure.

69 AAI, p.33.

6 Operating Expenditure in Next Period

6.1 Summary of Proposed Expenditure

The proposed operating expenditure in the next period is $335.7 m compared with the forecast $278.8 m in the present period, an increase of 20.4%. 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 a/	32.8	33.4	34.0	34.5	34.9	**169.7**
Admin & general	8.5	8.7	8.9	9.1	9.2	**44.3**
UAFG	13.9	13.9	13.0	11.8	10.3	**62.9**
Network development	7.8	8.1	8.5	8.8	8.7	**41.9**
Base opex	63.1	64.1	64.3	64.2	63.2	**318.8**
Non-base-year costs	3.7	3.4	2.9	2.4	1.7	**14.1**
Incremental growth	.2	.4	.5	.7	.9	**2.8**
	67.0	**67.9**	**67.8**	**67.3**	**65.8**	**335.7**

Source: AAI, p. 74, Table 6.1. Figures may not add due to rounding.
a/ Includes FRC costs previously stated separately.

Basis of the Proposed Expenditure

For the categories of "operating and maintenance" and "administration and general" Envestra has used the "base-year roll forward approach". [70] The base year used is FY 2010 (with 9 months actual and 3 months forecast). For the categories of UAFG and network development, Envestra states that because these components have not been static and are forecast to change considerably over the next period, they have been forecast year-by-year. [71]

Growth

The AAI states that the cost drivers of the business at a departmental activity 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. [72] The exceptions are costs (e.g., meter reading, maintenance, etc) that vary with incremental network expansion and number of customers. 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 7.6 to the AAI (*Capex Forecast - September 2010*).

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70 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.

71 AAI, p. 74.

72 AAI, p. 89.

Envestra states in its AAI (p. 89 *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.

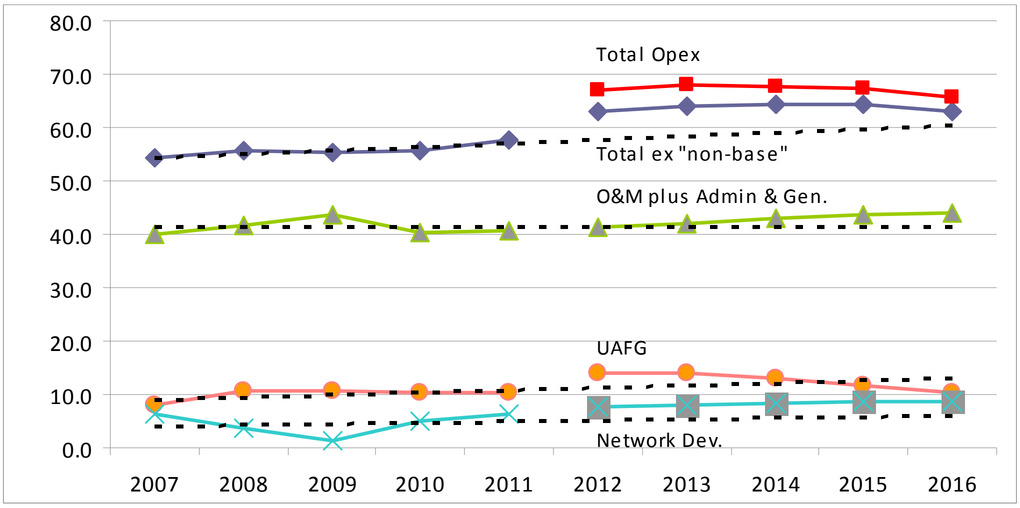
We note that the escalators have been derived independently and generally accord with our understanding of cost movements in the gas sector. However, we have not assessed their quantum, only their method of application as outlined below.

Movements from Present Level

Total operating expenditure in the first year of the next period is $67.0 m, an increase of $12.2 m (20%) above the base-year total. Average annual operating expenditure for the next period is $67.1 m compared with the base-year total of $55.8 m, an increase of 20%.

Figure 6.1shows 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)

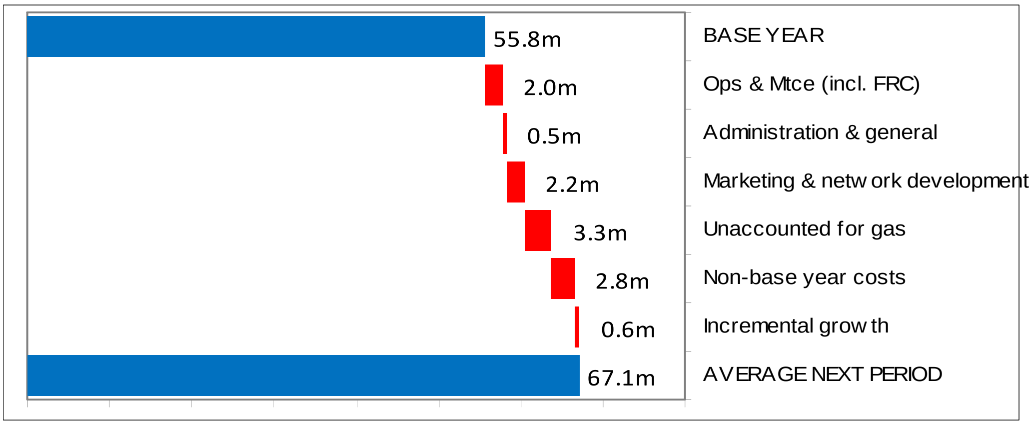


The chart shows that total expenditure is forecast to increase above the trend line at the start of the next period but then hold steady over the period. The change at the start of the period results from forecast increases in UAFG and network development costs (including marketing) and from the addition of new costs to the base-year level.

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.

Approximately half the total increase is attributable to increases in UAFG (due to a forecast increase in the price of gas) and marketing and network development costs. These are not technical matters and so have not been reviewed by us. The remainder of the increase is accounted for by increases in operating and maintenance and administration and general costs, attributable only to real cost escalation, the "step change and other cost increases included in the non-base-year component and an allowance for incremental growth.

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 only to project 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, in the preceding years in the present period is shown in Table 6.2. It illustrates that expenditure in the base year in the selected categories is below those in the preceding years and below the allowed level in all years.

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

FY >	2007	2008	2009	**2010**
Operations & maintenance a/	35.3	33.4	35.8	**31.9**
Administration & general	4.7	8.1	7.7	**8.3**
Total Incurred	40.0	41.5	43.5	**40.2**
Total Approved	41.1	42.1	42.1	**42.4**

a/ Includes FRC costs.

The AAI also states that expenditure in the categories used from the base year have been reviewed and no non-recurrent expenditure that should be removed from the base year had been identified. [73] It states that this was expected as, because of the global financial crisis, management had decided to avoid or defer non-essential expenditure in that year.

We consider that the base year selected is a reasonable representation of base-year costs for the expenditure categories for which the roll-forward methodology has been applied.

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.

[73] AAI, p. 81.

In chapter 5 of its AAI, Envestra sets out its arguments to illustrate that it is operating efficiently. We examine each of them 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."[74]

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. The Group holds 30.6% [75] 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:

(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. [76]

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. [77] 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. [78] 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

74 AAI, pp. 49-50.

75 AAI, p 38.

76 AAI, p. 56.

77 AAI, attachment 5.6.

78 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 [79] 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).

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 South Australia's changes in output and input quantities have led to a relatively strong productivity performance over the last 12 years, driven largely by significant reductions in operating expenditure. Its partial productivity of operating expenditure has grown strongly at the high annual rate of 4.2 per cent since 1999."[80]

It further concluded, "Envestra South Australia's TFP index exhibits relatively steady growth over the past 12 years. The average annual growth rate was 1.5 per cent for the period 1999 to 2010. Envestra South Australia's TFP growth over the period 1999 to 2006 was somewhat behind those of Victoria and JGN. Envestra South Australia had an average annual TFP growth rate of 1.6 per cent over this period compared to average annual growth rates of 2.5 per cent and 2.3 per cent for JGN and the Victorian industry, respectively."

"Envestra South Australia comes very close to matching JGN and the Victorian GDBs in terms of overall productivity levels (see figure A). Its TFP level is comparable to that of JGN and SP AusNet for the years 1999 to 2005. This is despite Envestra South Australia having the lowest overall energy density in 2010 and a domestic energy density that is comparable to JGN's but less than 40 per cent those of the three Victorian GDBs. Furthermore, Envestra South Australia is relatively small compared to JGN and the three Victorian GDBs. In terms of throughput it is less than half the size of each of the three Victorian GDBs and just over a quarter the size of JGN and in terms of customer numbers it is less than three quarters the size of each of the three Victorian GDBs and around 40 per cent the size of JGN."

Finally, the report concluded "While its operating environment conditions could be expected to place Envestra South Australia at a moderate disadvantage in comparisons of productivity levels, it performs relatively well by almost matching the performance of the larger included GDBs. Taking the differences in network density and size into account, the results of this

79 AAI, attachment 5.7.

80 AAI, attachment 5.7 p. 38.

study indicate that Envestra South Australia is likely to be a relatively efficient performer compared to the three Victorian GDBs”. [81]

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. It can thus be accepted that the report provides a supporting opinion that Envestra has, largely, obtained value for money in its past expenditures and, in the absence of evidence to the contrary, is likely to continue to do so.

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.[82] 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. [83]

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 South Australian network that “based on the relative position of Envestra South Australia over the range of indicators, Marksman concludes that the levels of capex and opex by Envestra South Australia over the current Access Arrangement period are reasonable, from a cost perspective only. This analysis does not take service levels into account (their consideration was outside the scope of that consultancy). It is not expected that differences in service levels would significantly impact costs of gas distribution businesses.” [84]

Further Analysis

Whilst the conclusion may be valid over the whole of the period considered, the relative performance of Envestra on some indicators since 2006 suggests that its cost performance may be a little above average. To test this we took the data in the report and analysed it for FY 2009, the most recent year for which data from all distributors is available and a year close to the year chosen by Envestra as its base year. We also calculated simple averages for

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

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

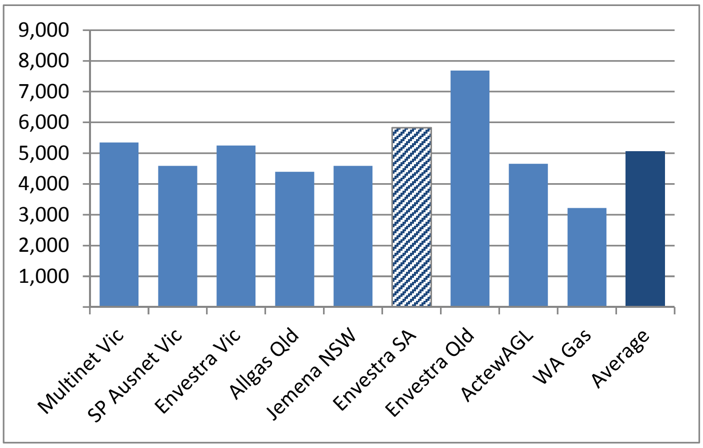
[83] This will result in operating expenditure for the Queensland distributors being understated.

[84] AAI, attachment 5.8 p. 16.

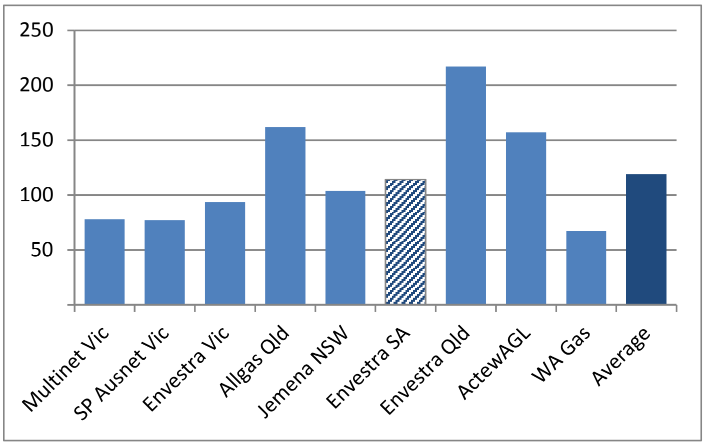
the indicators over the nine distributors. Figure 6.3 shows the operating expenditure performance on a cost per km and cost per customer basis for FY 2009.

Figure 6.3: Opex Performance Indicators in FY 2009

Opex /km



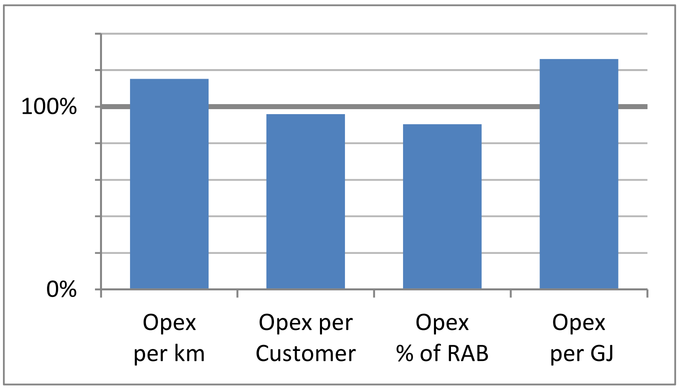
Opex/Customer



The analysis shows that in FY 2009 Envestra's South Australian network had the second highest operating expenditure per kilometre but that its operating expenditure per customer was in the middle of the range.

We also calculated a relative performance for the range of indicators used in the Marksman Report by calculating the Envestra South Australia performance as a percentage of average as shown in Figure 6.4

Figure 6.4: Relative Opex Performance in FY 2009



The analysis shows that Envestra is above the mean on two of the measures and below the mean on the other two. The differences from mean are within the range that may be due to differences in network characteristics. We therefore conclude that benchmarking does not indicate that Envestra's base-year operating expenditure is sufficiently outside the expected range to require further detailed analysis from a "bottom-up" perspective.

Further Consideration

A further consideration when assessing the efficiency of the base-year costs is that they reflect the condition of Envestra's network at that time. The point is particularly relevant, given the presence of significant lengths of mains in service in a deteriorated condition.

The link between the deferral within the period of mains replacement and rising operating costs and gas losses in the present period and the first part of the next is evident, underscoring the importance of this factor when determining reasonable levels of operating expenditure in the next period.

Conclusion on Base-Year Level of Expenditure

Considering these matters, we conclude that the base-year level of expenditure used for Envestra's forecasts is reasonable for the following reasons.

(a) Total operating expenditure in the present period is forecast to be similar to that approved by the ESCOSA in the last determination. [85]

(b) Comparison of expenditure in the base year with that in the preceding years (and with that allowed by ESCOSA) indicates that the base-year level is a reasonable representation of base-year costs for the expenditure categories in which the roll-forward methodology has been applied.

(c) Envestra has stated that following a review, it considers that non-recurrent costs are excluded from base year.

(d) We have not found any evidence that Envestra incurs additional costs as a direct result of the operating and management agreement with the APA Group. To the contrary, the information provided by Envestra indicates that costs are lower than would be incurred if it undertook the work itself. [86]

(e) The reports commissioned from KPMG and NERA support that view.

(f) The productivity report prepared by Economic Insights concludes that whilst its operating environment conditions could be expected to place Envestra at a moderate

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

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

disadvantage in comparisons of productivity levels, it performs relatively well by almost matching the performance of the larger included GDBs.

(g) 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 expenditure is not inconsistent with industry averages.

6.3 Operating and Maintenance Costs

The "base-year roll-forward" methodology has been used to forecast operating and maintenance costs in the next period. They are forecast to rise from the base year at a rate between 1.2% and 1.8% 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 84% to gas network related labour and 16% to network materials. [87] Maintenance costs are typically labour dominated, so we consider that this is appropriate.

We conclude the proposed operating and maintenance costs reasonable, as they are base-year costs with appropriate escalation applied. [88]

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 as well. These costs rise from the base year at a rate of between 0.9% and 2.4% 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 the proposed administration and general costs reasonable, as they are base-year costs with appropriate escalation applied. [89]

6.5 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.

Market development expenditure was curtailed severely in FY 2008 and FY 2009 and the business budgeted to continue with reduced expenditure relative to the regulatory benchmark in FY 2010. At the end of the 2009 winter, a review was made of the impacts of the reductions in network development expenditure on the business. The review demonstrated

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

[88] 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.

[89] See footnote 88.

that reduced expenditure was contributing to rapidly declining connection orders and a continuing reduction in average consumption per connection. The review was considered by the Envestra Board in December 2009 and an increase in network development expenditure was authorised for FY 2010: an additional $2.4 m above the approved budget with $2.2 m allocated to South Australia and $0.2 m allocated to Queensland. [90] Increased expenditure is planned for the next period to promote increased connections and usage.

Envestra has undertaken an economic evaluation of the proposed network development activities that demonstrates that the value of the increased gas volumes that would be transported through the network through the programmes have a positive net present value. The analysis confirmed that the proposed incentive programmes would yield a positive net present value over 10 years and result in lower delivered gas prices for customers.

The marketing component of this cost (and the portion of network development costs related to the provision of subsidies to customers), which accounts for approximately 86% of expenditure in this category, 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.

The remaining portion 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. [91] [92]

6.6 Unaccounted-for Gas

Gas Volume

We discussed UAFG and the considerations related to its reduction in section 4.2 of this report, noting that its forecast level in the next period, in volumetric terms as determined by Envestra, is expected to reduce from 2,193 TJ in FY 2012 to 1,626 TJ in FY 2016. This is equivalent to a reduction from 8.4% of gas input to 7.1% in the period.

We expressed the view in that section of the report that a faster rate of UAFG ought to be assumed to match the level of mains replacement expenditure that the business proposes.

Adoption of our proposed level of UAFG for the next period in volumetric terms is recommended.

Gas Price

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

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90 AAI, attachment 6.5 *Network Development Plan*. pp. 10-11.

91 We noted from the operating expenditure model that Envestra has applied escalation to network development costs in the ration 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 86% of the expenditure is proposed to be on market development programmes (principally, advertising and incentives) and only 14% on operational support. We consider a more appropriate ratio would be 14% to electrical-and-gas-worker labour and 86% 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 immaterial.

92 See footnote 88.

6.7 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, [93] and
- operating expenditure "step changes".

They amount to $13.4 m over the period, as summarised in Table 6.3, in addition to which escalation factors and certain other items will increase costs in the future.

Table 6.3: Non-Base-Year Costs ($2010 m)

YE 30 June	2012	2013	2014	2015	2016	**Total**
Opex related to capex	0.2	(0.1)	(0.7)	(1.2)	(1.8)	**(3.6)**
Ad hoc projects	1.1	0.8	0.9	0.8	0.8	**4.5**
Step changes	2.3	2.6	2.5	2.5	2.5	**12.5**
Total Unescalated	**3.6**	**3.3**	**2.7**	**2.2**	**1.6**	**13.4**
Total Escalated	**3.7**	**3.4**	**2.9**	**2.4**	**1.7**	**14.1**

Source: AAI, p. 89, Table 6.2.

The effect of cost increases summarised in the table is to add around 4.4% to operating expenditure in the next period.

The changes are outlined on pages 80-89 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 cost 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

[93] Envestra calls these "one-off" costs.

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.

6.8 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 six capital expenditure projects that lead to increases in the base-year level of operating expenditure. These are shown in Table 6.4.

Table 6.4: Cost Increases Arising from Capital Works ($2010 m un-escalated)

YE 30 June	2012	2013	2014	2015	2016	**Total**
Replacement of domestic regulators	0.47					**0.47**
Pressure surveillance and control		0.11	0.13	0.24	0.24	**0.71**
Tanunda extension		0.00	0.00	0.01	0.01	**0.02**
McLaren Vale extension		0.00	0.00	0.00	0.00	**0.00**
IT costs		0.15	0.15	0.23	0.23	**0.76**
Leak repair cost saving	(0.24)	(0.39)	(0.99)	(1.63)	(2.30)	**(5.55)**
	0.23	**(0.13)**	**(0.71)**	**(1.16)**	**(1.82)**	**(3.59)**

Source: AAI, attachment 6.8.

The proposed operating expenditure in relation to domestic regulators (Business Case S03) constitutes a survey to determine the presence of unsuitable regulators in domestic installations and precedes the corresponding capital expenditure for their replacement. The regulators pose a potential safety risk and it a survey of all 276,000 properties connected to high and medium pressure mains is required to locate them. The costs are based on a contracted “spotting fee” for meter readers to undertake the survey and temporary office staff to process the data. These rates are market-tested. We consider the work prudent as it meets the criterion of prudent risk mitigation but note that a 20% contingency allowance has been added to the estimate. We consider that the inclusion of a contingency allowance is not appropriate for reasons that we have discussed in section 4.7 of this report.

The pressure surveillance and control item (Business Case S11) involves the cost of future maintenance of new equipment to control remotely 26 critical transmission pressure regulators and 10 critical valves, and to operate 134 pressure-monitoring data loggers. The costs have been estimated in accordance with established schedules for similar assets. The estimate takes account of savings in maintenance of existing mechanical data loggers but we consider that the estimated labour required for visits to capture data from the new loggers is twice that involved for the present data loggers. We further note that a 20% contingency allowance has been added to the estimate. We consider that the inclusion of a contingency allowance is not appropriate for reasons that we have discussed in section 4.7 of this report. Because of these factors, we consider that the cost of one additional full-time-equivalent employee, rather than two is all that should be approved. We consider the project prudent as it will improve asset performance and service levels but costs not efficient and recommend that the labour and vehicle component be reduced by 50%.

The proposed Tanunda and McLaren Vale network extensions (Business Cases S25 and S56) involve future maintenance ($0.024 m). The increase is commensurate with the size of the extension and so we consider the expenditure prudent and efficient.

IT expenditure (Business Case S21) is associated with the planned “roadmap initiative” capital expenditure projects. We note that these projects were included in the access arrangement proposal for the present period and were approved by the ESCOSA but were deferred by Envestra due to spending constraints during the period. The expenditure ($0.6 m for field data capture and $0.16 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 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 the forecast.

Savings in the cost of leak repairs (Business Case S60) accompany the proposed mains replacement programme and are significant ($5.5 m). [94] Total leak repairs are expected to reduce from 2,600 p.a. to approximately 1,000 by the end of the period. We reviewed the basis of the calculation and considered it reasonable. We comment on the prudence and efficiency of the overall mains replacement programme in Section 4.2 of this report.

(b) Cost Increases Related to Ad Hoc Projects

Envestra has proposed four ad hoc projects in the next period as shown in Table 6.5. The expenditure is not expected continue indefinitely.

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94 Savings arising from the reduction of UAFG are recognised separately.

Table 6.5: Cost Increases Arising from Ad Hoc Projects ($2010 m un-escalated)

YE 30 June	2012	2013	2014	2015	2016	Total
Inlet data capture	0.35	0.25	0.25	0.25	0.25	**1.36**
Holes in meter boxes	0.52	0.52	0.52	0.52	0.52	**2.58**
Gas contaminent	0.03	0.05	0.10	0.05	0.05	**0.28**
Nil gas consumption	0.16	0.03	0.03	0.03	0.03	**0.27**
	1.05	**0.84**	**0.89**	**0.84**	**0.84**	**4.47**

Source: AAI, attachment 6.8.

Envestra's asset database does not contain information on the location of services (inlets). Accurate records would assist the management of emergency leak responses and ensuring that this information is available to third parties mitigates the risk of damage to the network. A project is proposed to capture these details for 5,000 industrial and commercial consumer sites and 3,250 unit development sites where the risk is considered highest (Business Case S07). This will involve site visits and data entry. The proposed cost ($1.35 m) is predominantly labour-related but includes transport and computer licensing expenses. We note that costs include a 15% allowance for project management and a 10% contingency allowance. We consider the work prudent as it represents good industry practice and will improve safety and service for customers. However, we do not consider the costs proposed efficient due to the addition of the project management and contingency allowances. We consider that the contractor's charge out-rate should be sufficient to cover the costs of project management and that the inclusion of a contingency allowance is not appropriate for reasons that we have discussed in section 4.7 of this report. We recommend that the labour component of the costs be reduced by 20%.

(We note that this item was accepted as a "material change" in relation to the present period and thus the business has already received a regulatory allowance in relation to work for which it now requests a further allowance.)

The Office of the Technical Regulator has raised concerns with Envestra about wall-mounted gas meter boxes that have holes leading into wall cavities. In certain circumstances, gas could accumulate in building, creating a risk of fire or explosion. Envestra proposes to survey metering installations during FY 2011, followed by prioritised rectification during the next period (Business Case S45). The cost estimate is based on five contractors or Envestra staff repairing approximately 25,000 sites p.a. We consider the work prudent, based on the need to mitigate safety risk. The basis of the cost estimates is considered reasonable and therefore we consider the expenditure efficient as well.

An Adelaide manufacturer recently suffered a loss of gas supply because of oil contamination in the gas. As a result, Envestra plans to locate and extract any remaining oil from the network (Business Case S53). Operating expenditure is involved in the investigatory work and in removal of the oil. We consider the work prudent (as it reduces the risk of interruption to customers and protects service levels) and efficient, as the basis of estimate is reasonable.

Envestra has identified 5,000 meters registering 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 S16). A small provision has been made to make such checks annually for any newly emerging instances. We consider the programme prudent as it will improve cost efficiency and reduce safety risk. 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 be 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 6.6.

Virginia Gate Station

Upgrading of the Virginia gate station is required to accommodate existing and future demand in the area (Business Case S04) and the related operating costs are the subject of this step change. Epic Energy would upgrade the station and increase the rental Envestra pays for its use. It has indicated an increase of $0.5m p.a. We consider the upgrading prudent as it is required to meet present and future demand (customer service levels) and have no argument against the cost as it is a contractual arrangement with a third party.

Table 6.6: Cost Increases Arising from Step Changes ($2010 m un-escalated)

YE 30 June	2012	2013	2014	2015	2016	**Total**
Virginia gate station upgrade	0.51	0.51	0.51	0.51	0.51	**2.55**
Gas market administration	0.06	0.06	0.06	0.06	0.06	**0.30**
Meter change notification	0.14	0.14	0.14	0.14	0.14	**0.68**
UAFG analytical support	0.25	0.25	0.15	0.05	(0.05)	**0.64**
HDPE survey	0.38	0.38	0.38	0.38	0.38	**1.88**
Standby crews	0.53	0.35	0.35	0.35	0.35	**1.94**
New road authority specification	0.41	0.41	0.41	0.41	0.41	**2.03**
Knowledge management	0.00	0.30	0.30	0.30	0.30	**1.20**
Real increase in insurance	0.07	0.15	0.21	0.32	0.43	**1.18**
Connection compliance reporting	0.00	0.02	0.02	0.02	0.02	**0.08**
	2.34	**2.56**	**2.52**	**2.53**	**2.54**	**12.48**

Source: AAI, attachment 6.8.

Gas Market Administration

The item titled "gas market administration" (Business Case S10) 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 is a new external 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 S26). Presently, to optimise the use of resources, the changing of 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, following discussion with the South Australian Energy Industry Ombudsman, Envestra plans to give advance notification of interruptions for this type of work. In addition to the cost of arranging notification, the increased service level will 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, consider the direct costs to send notices reasonable and agree that there will be additional administration time required.

However, we consider that much of the productivity loss could be eliminated by good planning and by providing a notification "window"[95] to customers to allow some flexibility on when the work can be done. We therefore do not consider the costs efficient, recommending that only the allowance to cover the direct costs and administration be allowed.

(We note that an allowance of $0.030 m p.a. was approved in relation to the present period and thus the business has already received a regulatory allowance in relation to work for which it now requests a further allowance.)

Support for Analysis of UAFG

Envestra has proposed two additional employees to analyse and investigate underlying causes of UAFG and to co-ordinate UAFG reduction strategies (Business Case S39). The proposed cost covers the cost of a data analyst and an engineer. The costs are offset by estimates of UAFG reduction from the third year of the period, increasing over the last two years of the period. By the end of the period, UAFG savings are forecast to exceed the costs.

We consider that this step change is prudent as it seeks to reduce one of Envestra's largest annual costs, and efficient because, over time, the savings are expected to exceed the cost of undertaking the work.

Survey of Polyethylene Pipe Condition

Recent failures of high-density polyethylene pipe at "squeeze-off" points have raised concerns about the long-term safety of pipelines made of this material. An initial leak survey of the mains concerned was conducted in 2008-2009 and mains are generally surveyed once every five years. However, Envestra has proposed that in order to manage the risk, the 1,800 km of these mains should be surveyed each year (Business Case S47). We consider the work prudent, as it is an appropriate response to an identified safety risk. However, the cost estimate includes a 5% contingency allowance that should be removed for the reasons previously stated in this section of the report. In addition, noting that the base level of operating expenditure includes inspection of mains every five years, the cost of annual inspections should be reduced by a further 20% to account for the existing provision for every fifth year. Thus, an efficient level of expenditure for this work is considered 75% of the level proposed by Envestra.

Proposed Additional Standby Crews

Envestra proposes to recruit 12 new employees to establish three additional three-man work crews and three first-response field operatives to cover after-hour emergencies (between 7 p.m. and 7.30 a.m.) on all days (Business Case S48). This work is presently undertaken by existing field staff, who provide standby support after normal business hours in addition to working a normal eight-hour day. The reasons given are the need to address worker fatigue, reduce the risk of injury and the wish to comply with the Government's amended *Working Hours Code of Practice* introduced on 1 July 2010. It is acknowledged that the code's requirements are not mandatory. Details were given of the workload of the existing crews. We note that the mains replacement programme is expected to result in a significant and progressive drop in the number leaks, with an estimated drop of 60% by the end of the next period. This will see a proportionate drop-off in the work required outside normal business hours. Envestra does not appear to have allowed for this reduction in its business case; nor has the cost of other alternatives to providing appropriate stand-down periods been identified.

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[95] 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.

We therefore do not consider that Envestra has demonstrated that the proposed expenditure is prudent or efficient.

New Specification for Reinstatement of Road Surfaces after Excavation

Envestra must now comply with more stringent requirements for the reinstatement and resurfacing of roads after excavation, introduced by the DTEI on 1 July 2010 (Business Case S52). The operating expenditure component related to this new requirement is associated with leak repairs and the forecast expenditure assumes that the number of leaks occurring in FY 2010 will continue unabated throughout the next period. However, the number is expected to decline as the mains replacement programme proceeds. We consider the expenditure prudent, as it is required to meet an obligation imposed by an external party. We do not consider the proposed expenditure efficient, as it does not account for the expected reduction in the number of leak repairs. We recommend a reduction in the expenditure in proportion to the expected lower level of leak repairs over the period.

Knowledge Management

Envestra intends to develop a more formal process to manage its documentation (Business Case S01). Around $1 m of the estimated cost of $1.2 m 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 the forecast.

(We note that this project was included in the access arrangement proposal for the present period but was not implemented due to spending constraints during the period.)

Real Increase in Insurance Costs

We have not reviewed this matter (Business Case S62), as it is not a technical matter.

Connection Compliance Reporting

The ESCOSA has advised Envestra that its approach to reporting its connection compliance is inadequate and that, in future, it will be required to report actual outcomes rather than estimates. Envestra states that this decision, which represents a change in a regulatory obligation, requires it to develop a new reporting system (capital expenditure) and to implement appropriate information collection and input processes (operating expenditure) (Business Case S57). We consider the expenditure prudent and efficient, as it meets the criterion of being a new or changed regulatory obligation.

(d) Other Items Leading to Increases in Operating Expenditure

Re-Classification of Capital Expenditure Items as Operating Expenditure

In section 4.5 of this report, we identified two capital expenditure items that we considered ought to be expensed and not added to the capital base. They were the refurbishment of valves and minor remedial work on transmission pressure.

We consider the work prudent and efficient (with the associated contingency allowances removed) and we recommend that additional operating expenditure be allowed accordingly.

Adjustment for Incremental Growth

Envestra has proposed adjustments in its level of operating expenditure over the next period to allow for forecast growth in the size of its operation. It states that whilst the majority of its operating expenditure is fixed in the short term, an incremental cost of $17.85 per additional customer will be incurred. [96] We noted that this sum included $8.07 for periodic meter change (PMC) costs. Periodic meter changes are a capital expenditure item and thus should not be included in this calculation. We have not reviewed the customer growth forecasts that have been used as this was outside our terms of reference.

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. However, 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 Increases

The adjustments we have proposed in this section of the text are summarised in Table 6.7. The adjustments are expressed before the application of cost escalators with cost escalation then applied to the net adjustment (a reduction) in the same was as Envestra applied it to its total "non-base-year" costs. The adjustment for incremental growth is shown separately.

Table 6.7: Recommended Adjustments ($2010 m)

YE 30 June	2012	2013	2014	2015	2016	**Total**
Expenditure reductions						
Replacement of domestic regulators	0.09					**0.09**
Pressure surveillance and control		0.05	0.05	0.09	0.09	**0.27**
IT costs		0.15	0.15	0.23	0.23	**0.76**
Inlet data capture	0.05	0.05	0.05	0.05	0.05	**0.23**
Nil gas consumption	0.16	0.03	0.03	0.03	0.03	**0.27**
Meter change notification	0.06	0.06	0.06	0.06	0.06	**0.30**
HDPE survey	0.09	0.09	0.09	0.09	0.09	**0.47**
Standby crews	0.53	0.35	0.35	0.35	0.35	**1.94**
New road authority specification	0.04	0.06	0.12	0.18	0.25	**0.65**
Knowledge management	0.00	0.30	0.30	0.30	0.30	**1.20**
	1.02	1.13	1.19	1.38	1.45	**6.18**
Less additions:						
Refurbishment of valves	0.25	0.25	0.25	0.25	0.25	**1.27**
AEI remediation	0.03	0.03	0.03	0.03	0.03	**0.15**
Net reduction before escalation	**0.74**	**0.85**	**0.91**	**1.10**	**1.16**	**4.76**
Plus real cost escalation	0.02	0.04	0.06	0.08	0.08	**0.27**
Non-base-year reduction	0.76	0.89	0.96	1.17	1.25	**5.03**
Incremental growth reduction	0.09	0.17	0.25	0.33	0.42	**1.25**
Total reduction	**0.85**	**1.06**	**1.21**	**1.50**	**1.66**	**6.28**

The impact of the proposed adjustments is to reduce the total level of step changes and other cost increases proposed by Envestra from (including the factor for cost escalation and after

[96] AAI, section 6.7 p. 84.

adding items that we considered ought to be expenses, not added to the capital base) from $14.1 m to $7.8 m.

6.9 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 $329.4 m, as shown in Table 6.8.

Table 6.8: Recommended Opex in Next Period ($2010 m)

YE 30 June	2012	2013	2014	2015	2016	**Total**
Opex as proposed by Envestra	67.0	67.9	67.8	67.3	65.8	**335.7**
Proposed reduction	(0.8)	(1.1)	(1.2)	(1.5)	(1.7)	**(6.3)**
	66.1	**66.8**	**66.5**	**65.8**	**64.1**	**329.4**

The recommended level is an estimate, as we did not have sufficient information available 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, although we believe our calculations to be based on reasonable grounds. The business should therefore be asked to confirm our calculations at an appropriate time, if our recommended level of expenditure is endorsed by the AER.

We further note that these adjustments should be accompanied by lower levels of UAFG than those projected by Envestra in the next period, as noted in section 6.6 of this report.

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) The proposed capital expenditure in the next period is considered prudent and efficient, subject to the removal of contingency allowances, the reassessment of the rate of capitalisation of overheads and some other adjustments. The adjustments are summarised in section 4.9 of the report.

(c) The business may react to the effects on UAFG of mains replacement work as it proceeds by modifying the rate of replacement accordingly and we consider that this would be a valid response, as it is optimality of the cost of leakage *vs*. mains replacement cost that should be sought, not leakage reduction for its own sake. We suggest to the AER that this possibility be considered in its decision.

(d) The base-year level of operating expenditure is considered efficient.

(e) Adjustment is needed to several of the proposed "step changes" and other additional costs. Details are given in section 6.8 of the report. In addition, an adjustment will be required to reflect the more rapid reduction in UAFG that we foresee, as noted in sections 4.2 and 6.6 of the report.

(f) Envestra has proposed a large increase in the price of gas for UAFG in the next period and an increase in marketing expenditure. These matters account for about half of the proposed increase in operating expenditure but are not technical in nature and so have not been reviewed by us.

(g) The forecast rate of reduction in unaccounted-for gas is considered insufficient and so we have proposed a faster rate for its reduction, as noted above.

(h) The resulting recommended level of operating expenditure in the next period is summarised in section 6.9 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