EDB Information Disclosure Requirements
Information Templates

Schedules 1–10
excluding 5f–5h

Company Name	Alpine Energy Ltd
Disclosure Date	31 August 2026
Disclosure Year (year ended)	31 March 2026

Templates for Schedules 1–10 excluding 5f–5h

Prepared 2 June 2026

Table of Contents

Schedule	Schedule name
1	ANALYTICAL RATIOS
2	REPORT ON RETURN ON INVESTMENT
3	REPORT ON REGULATORY PROFIT
3a	REPORT ON INCREMENTAL ROLLING INCENTIVE SCHEME
4	REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)
5a	REPORT ON REGULATORY TAX ALLOWANCE
5b	REPORT ON RELATED PARTY TRANSACTIONS
5c	REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE
5d	REPORT ON COST ALLOCATIONS
5e	REPORT ON ASSET ALLOCATIONS
6a	REPORT ON CAPITAL EXPENDITURE FOR THE DISCLOSURE YEAR
6b	REPORT ON OPERATIONAL EXPENDITURE FOR THE DISCLOSURE YEAR
7	COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE
8	REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES
9a	ASSET REGISTER
9b	ASSET AGE PROFILE
9c	REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES
9d	REPORT ON EMBEDDED NETWORKS
9e	REPORT ON NETWORK DEMAND
10	REPORT ON NETWORK RELIABILITY
10(vi)	REPORT ON NETWORK RELIABILITY (Worst-performing Feeders)

Disclosure Template Instructions

This document forms Schedules 1–10 to the Electricity Distribution Information Disclosure (Non-material) Amendment Determination 2026 [2026] NZCC 21.

The Schedules take the form of templates for use by EDBs when making disclosures under clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1, and 2.5.2 of the Electricity Distribution Information Disclosure Determination 2012, as amended.

Company Name and Dates

To prepare the templates for disclosure, the supplier's company name should be entered in cell C8, the date of the last day of the current (disclosure) year should be entered in cell C12, and the date on which the information is disclosed should be entered in cell C10 of the CoverSheet worksheet.

The cell C12 entry (current year) is used to calculate disclosure years in the column headings that show above some of the tables and in labels adjacent to some entry cells. It is also used to calculate the 'For year ended' date in the template title blocks (the title blocks are the light green shaded areas at the top of each template).

The cell C8 entry (company name) is used in the template title blocks.

Dates should be entered in day/month/year order (Example -"1 April 2023").

Data Entry Cells and Calculated Cells

Data entered into this workbook may be entered only into the data entry cells. Data entry cells are the bordered, unshaded areas (white cells) in each template. Under no circumstances should data be entered into the workbook outside a data entry cell.

In some cases, where the information for disclosure is able to be ascertained from disclosures elsewhere in the workbook, such information is disclosed in a calculated cell.

Validation Settings on Data Entry Cells

To maintain a consistency of format and to help guard against errors in data entry, some data entry cells test keyboard entries for validity and accept only a limited range of values. For example, entries may be limited to a list of category names, to values between 0% and 100%, or either a numeric entry or the text entry "N/A". Where this occurs, a validation message will appear when data is being entered. These checks are applied to keyboard entries only and not, for example, to entries made using Excel's copy and paste facility.

Conditional Formatting Settings on Data Entry Cells

Schedule 2 cells G79 and I79:L79 will change colour if the total cashflows do not equal the corresponding values in table 2(ii).

Schedule 4 cells P99:P106 and P107 will change colour if the RAB values do not equal the corresponding values in table 4(ii).

Schedule 9b columns AA to AE (2013 to 2017) contain conditional formatting. The data entry cells for future years are hidden (are changed from white to yellow).

Schedule 9b cells in rows 10 to 60 of the column "Items at end of year (quantity)" will change colour if the total assets at year end for each asset class does not equal the corresponding values in column I in Schedule 9a.

Schedule 9c cell G30 will change colour if G30 (overhead circuit length by terrain) does not equal G18 (overhead circuit length by operating voltage).

Inserting Additional Rows and Columns

The schedule 4, 5b, 5c, 5d, 5e, 6a, 8, 9d, and 9e templates may require additional rows to be inserted in tables marked 'include additional rows if needed' or similar. Column A schedule references should not be entered in additional rows, and should be deleted from additional rows that are created by copying and pasting rows that have schedule references.

Additional rows in the schedule 5c, 6a, and 9e templates must not be inserted directly above the first row or below the last row of a table. This is to ensure that entries made in the new row are included in the totals.

The schedule 5d and 5e templates may require new cost or asset category rows to be inserted in allocation change tables 5d(iii) and 5e(ii). Accordingly, cell protection has been removed from rows 77 and 78 of the respective templates to allow blocks of rows to be copied. The four steps to add new cost category rows to table 5d(iii) are: Select Excel rows 69:77, copy, select Excel row 78, insert copied cells. Similarly, for table 5e(ii): Select Excel rows 70:78, copy, select Excel row 79, then insert copied cells.

The template for schedule 8 may require additional columns to be inserted between column L and Q, and between U and AF. If inserting additional columns, headings will need to be copied into the added columns. Additionally, the formulas for standard consumers total, non-standard consumers totals and total for all consumers will need to be copied into the cells of the added columns. The column headings and formulas can be found in the equivalent cells of the existing columns.

Disclosures by Sub-Network

If the supplier has sub-networks, schedules 8, 9a, 9b, 9c, 9e, and 10 must be completed for the network and for each sub-network. A copy of the schedule worksheet(s) must be made for each sub-network and named in the subnetwork box at the top of the sheet.

Description of Calculation References

Calculation cell formulas contain links to other cells within the same template or elsewhere in the workbook. Key cell references are described in a column to the right of each template. These descriptions are provided to assist data entry. Cell references refer to the row of the template and not the schedule reference.

Worksheet Completion Sequence

Calculation cells may show an incorrect value until precedent cell entries have been completed. Data entry may be assisted by completing the schedules in the following order:

1. Coversheet
2. Schedules 5a–5e
3. Schedules 6a–6b
4. Schedule 8
5. Schedule 3
6. Schedule 4
7. Schedule 2
8. Schedule 7
9. Schedules 9a–9e
10. Schedule 10

Cell colouring

1. White: Data entry
2. **Yellow: Formula/Blank/Empty columns**
3. Dark grey: Blank/Empty columns

Note: The template for the new Schedule 3a is in a new layout to improve data entry and processing. These schedules follow the same colour formatting as other schedules, with white cells requiring data entry.

Company Name	**Alpine Energy Ltd**
For Year Ended	**31 March 2026**

SCHEDULE 1: ANALYTICAL RATIOS

This schedule calculates expenditure, revenue and service ratios from the information disclosed. The disclosed ratios may vary for reasons that are company specific and, as a result, must be interpreted with care. The Commerce Commission will publish a summary and analysis of information disclosed in accordance with this ID determination. This will include information disclosed in accordance with this and other schedules, and information disclosed under the other requirements of this determination.

This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

7 **1(i): Expenditure metrics**

sch ref		Expenditure per GWh energy delivered to ICPs ($/GWh)	Expenditure per average no. of ICPs ($/ICP)	Expenditure per MW maximum coincident system demand ($/MW)	Expenditure per km circuit length ($/km)	Expenditure per MVA of capacity from EDB-owned distribution transformers ($/MVA)
8						
9	**Operational expenditure**	41,655	1,001	233,089	7,709	52,923
10	Network	7,925	190	44,345	1,467	10,069
11	Non-network	33,731	810	188,744	6,242	42,854
12						
13	**Expenditure on assets**	40,690	978	227,685	7,530	51,696
14	Network	36,585	879	204,716	6,771	46,481
15	Non-network	4,105	99	22,969	760	5,215
16						

17 **1(ii): Revenue metrics**

sch ref		Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
18			
19	**Total consumer line charge revenue**	100,155	2,406
20	Standard consumer line charge revenue	123,429	2,244
21	Non-standard consumer line charge revenue	27,818	633,183
22			

23 **1(iii): Service intensity measures**

sch ref			
24			
25	Demand density	33	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
26	Volume density	185	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
27	Connection point density	8	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
28	Energy intensity	24,024	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*
29			

30 **1(iv): Composition of regulatory income**

sch ref		($000)	% of revenue
31			
32	Operational expenditure	34,082	41.56%
33	Pass-through and recoverable costs excluding financial incentives and wash-ups	17,677	21.56%
34	Total depreciation	14,002	17.07%
35	Total revaluations	10,410	12.69%
36	Regulatory tax allowance	4,191	5.11%
37	Regulatory profit/(loss) including financial incentives and wash-ups	22,461	27.39%
38	**Total regulatory income**	82,004	
39			

40 **1(v): Reliability**

sch ref			
41			
42	Interruption rate	16.31	*Interruptions per 100 circuit km*

Company Name	**Alpine Energy Ltd**
For Year Ended	**31 March 2026**

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

This schedule requires information on the Return on Investment (ROI) for the EDB relative to the Commerce Commission's estimates of post tax WACC and vanilla WACC. EDBs must calculate their ROI based on a monthly basis if required by clause 2.3.3 of this ID Determination or if they elect to. If an EDB makes this election, information supporting this calculation must be provided in 2(iii).

EDBs must provide explanatory comment on their ROI in Schedule 14 (Mandatory Explanatory Notes).

This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref				
7	**2(i): Return on Investment**	**CY-2**	**CY-1**	**Current Year CY**
8				
9	**ROI – comparable to a post tax WACC**	**%**	**%**	**%**
10	Reflecting all revenue earned	5.96%	2.92%	6.40%
11	Excluding revenue earned from financial incentives	5.30%	2.12%	8.46%
12	Excluding revenue earned from financial incentives and wash-ups	5.33%	2.16%	5.97%
13				
14	**Mid-point estimate of post tax WACC**	6.05%	6.18%	5.90%
15	25th percentile estimate	5.37%	5.50%	5.17%
16	75th percentile estimate	6.73%	6.86%	6.62%
17				
18				
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	6.66%	3.64%	6.95%
21	Excluding revenue earned from financial incentives	6.00%	2.84%	9.10%
22	Excluding revenue earned from financial incentives and wash-ups	6.03%	2.88%	6.60%
23				
24	**WACC rate used to set regulatory price path**	4.57%	4.57%	7.10%
25				
26	**Mid-point estimate of vanilla WACC**	6.75%	6.90%	6.53%
27	25th percentile estimate	6.07%	6.22%	5.81%
28	75th percentile estimate	7.43%	7.58%	7.26%
29				
30	**2(ii): Information Supporting the ROI**		**($000)**	
31				
32	Total opening RAB value	338,231		
33	*plus* Opening deferred tax	(21,613)		
34	**Opening RIV**		316,618	
35				
36	**Line charge revenue**		81,946	
37				
38	Expenses cash outflow	51,759		
39	*add* Assets commissioned	25,375		
40	*less* Asset disposals	83		
41	*add* Tax payments	2,706		
42	*less* Other regulated income	57		
43	**Mid-year net cash outflows**		79,700	
44				
45	**Term credit spread differential allowance**		–	
46				
47	Total closing RAB value	360,545		
48	*less* Adjustment resulting from asset allocation	614		
49	*less* Lost and found assets adjustment	–		
50	*plus* Closing deferred tax	(23,098)		
51	**Closing RIV**		336,833	
52				
53	**ROI – comparable to a vanilla WACC**			6.95%
54				
55	Leverage (%)			41%
56	Cost of debt assumption (%)			5.56%
57	Corporate tax rate (%)			28%
58				
59	**ROI – comparable to a post tax WACC**			6.40%
60				

Company Name	**Alpine Energy Ltd**
For Year Ended	**31 March 2026**

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

This schedule requires information on the Return on Investment (ROI) for the EDB relative to the Commerce Commission's estimates of post tax WACC and vanilla WACC. EDBs must calculate their ROI based on a monthly basis if required by clause 2.3.3 of this ID Determination or if they elect to. If an EDB makes this election, information supporting this calculation must be provided in 2(iii).
EDBs must provide explanatory comment on their ROI in Schedule 14 (Mandatory Explanatory Notes).
This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

2(iii): Information Supporting the Monthly ROI

Opening RIV	N/A

	Line charge revenue	Expenses cash outflow	Assets commissioned	Asset disposals	Other regulated income	Monthly net cash outflows
April						–
May						–
June						–
July						–
August						–
September						–
October						–
November						–
December						–
January						–
February						–
March						–
Total	–	–	–	–	–	–

Tax payments	N/A
Term credit spread differential allowance	N/A
Closing RIV	N/A
Monthly ROI – comparable to a vanilla WACC	N/A
Monthly ROI – comparable to a post tax WACC	N/A

2(iv): Year-End ROI Rates for Comparison Purposes

Year-end ROI – comparable to a vanilla WACC	6.36%
Year-end ROI – comparable to a post tax WACC	5.72%

** these year-end ROI values are comparable to the ROI reported in pre 2012 disclosures by EDBs and do not represent the Commission's current view on ROI.*

2(v): Financial Incentives and Wash-Ups

IRIS incentive adjustment	(9,158)		
Purchased assets – avoided transmission charge	–		
Innovation and non-traditional solutions recovered amount	–		
Quality incentive adjustment	(170)		
Other CPP financial incentives	–		
Financial incentives		(9,328)	
Impact of financial incentives on ROI		–2.15%	
Input methodology claw-back	–		
CPP application recoverable costs	–		
CPP Urgent project allowance	–	Not Required before DY	
Reopener event allowance	–	Not Required before DY	
Wash-up draw down amount	10,848	Not Required before DY	
Other CPP wash-ups	–		
Wash-up costs		10,848	
Impact of wash-up costs on ROI		2.49%	

Company Name	**Alpine Energy Ltd**
For Year Ended	**31 March 2026**

SCHEDULE 3: REPORT ON REGULATORY PROFIT

This schedule requires information on the calculation of regulatory profit for the EDB for the disclosure year. All EDBs must complete all sections and provide explanatory comment on their regulatory profit in Schedule 14 (Mandatory Explanatory Notes).
This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

7		**3(i): Regulatory Profit**	**($000)**
8		**Income**	
9		Line charge revenue	81,946
10	*plus*	Gains / (losses) on asset disposals	0
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)	57
12			
13		**Total regulatory income**	82,004
14		**Expenses**	
15	*less*	Operational expenditure	34,082
16			
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups	17,677
18			
19		**Operating surplus / (deficit)**	30,244
20			
21	*less*	Total depreciation	14,002
22			
23	*plus*	Total revaluations	10,410
24			
25		**Regulatory profit / (loss) before tax**	26,652
26			
27	*less*	Term credit spread differential allowance	–
28			
29	*less*	Regulatory tax allowance	4,191
30			
31		**Regulatory profit/(loss) including financial incentives and wash-ups**	22,461
32			

33	**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**		**($000)**	
34	**Pass through costs**			
35	Electricity lines service charge payable to Transpower	15,537	Not Required before D\	
36	Transpower new investment contract charges	1,479	Not Required before D\	
37	System operator services	–	Not Required before D\	
38	Rates	176		
39	Commerce Act levies	150		
40	Industry levies	240		
41	CPP or DPP specified pass-through costs	–		
42	**Recoverable costs excluding financial incentives and wash-ups**			
43	Independent engineer costs	–	Not Required before D\	
44	FENZ levies	95	Not Required before D\	
45	Extended reserves allowance	–		
46	Other CPP recoverable costs excluding financial incentives and wash-ups	–		
47	**Pass-through and recoverable costs excluding financial incentives and wash-ups**			17,677
48				

49	**3(iv): Merger and Acquisition Expenditure**	
50		**($000)**
51	Merger and acquisition expenditure	–
52		
53	*Provide commentary on the benefits of merger and acquisition expenditure to the electricity distribution business, including required disclosures in accordance with section 2.7, in Schedule 14 (Mandatory Explanatory Notes)*	
54	**3(v): Other Disclosures**	
55		**($000)**
56	Self-insurance allowance	–

SCHEDULE 3a: REPORT ON INCREMENTAL ROLLING INCENTIVE SCHEME

This schedule requires information on the calculation of IRIS incentive amounts. All non-exempt EDBs must complete this section.

This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

Please note; only the white cells should be filled in (i.e. F7 - J7, F10 - J12, F15 - J17). Forecast values should be filled in for all years, actual values should be filled in for all years where known.

Section	Row	Context	Category1	Category2	RY1	RY2	RY3	RY4	RY5	Total over / (under) spend
3a: Incremental Rolling Incentive Scheme	7		**Current Year**	**Current Year**	CY-2	CY-1	CY	CY+1	CY+2	

Section	Row	Context	Category1	Category2	RY1 ($000)	RY2 ($000)	RY3 ($000)	RY4 ($000)	RY5 ($000)	Total over / (under) spend
3a: Incremental Rolling Incentive Scheme	10		Opex incentive amounts	Forecast opex	35,439	36,448	37,761	39,152	40,607	
3a: Incremental Rolling Incentive Scheme	11		Opex incentive amounts	Actual opex	34,082					
3a: Incremental Rolling Incentive Scheme	12	+	Opex incentive amounts	Plus lease payments	-					
3a: Incremental Rolling Incentive Scheme	13		Opex incentive amounts	Actual opex for IRIS	34,082	-	-	-	-	
3a: Incremental Rolling Incentive Scheme	14		Opex incentive amounts	Expenditure variance to opex allowance	(1,356)	-	-	-	-	(1,356)
3a: Incremental Rolling Incentive Scheme	15		Capex incentive amounts	Forecast aggregate value of commissioned assets	34,041	31,634	28,623	25,578	30,228	
3a: Incremental Rolling Incentive Scheme	16		Capex incentive amounts	Actual commissioned assets	25,375					
3a: Incremental Rolling Incentive Scheme	17	-	Capex incentive amounts	Less right-of-use assets						
3a: Incremental Rolling Incentive Scheme	18		Capex incentive amounts	Actual commissioned assets for IRIS	25,375	-	-	-	-	
3a: Incremental Rolling Incentive Scheme	19		Capex incentive amounts	Expenditure variance to commissioned assets allowance	(8,666)	-	-	-	-	(8,666)

Company Name	Alpine Energy Ltd
For Year Ended	31 March 2026

SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

This schedule requires information on the calculation of the Regulatory Asset Base (RAB) value to the end of this disclosure year. This informs the ROI calculation in Schedule 2.
EDBs must provide explanatory comment on the value of their RAB in Schedule 14 (Mandatory Explanatory Notes). This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

7 4(i): Regulatory Asset Base Value (Rolled Forward)

sch ref			RAB	RAB	RAB	RAB	RAB
8			31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 March 2026
9			($000)	($000)	($000)	($000)	($000)
10		**Total opening RAB value**	236,905	267,127	293,278	313,092	338,231
12	*less*	**Total depreciation**	9,610	11,083	11,923	13,664	14,002
14	*plus*	**Total revaluations**	16,319	17,777	11,785	7,860	10,410
16	*plus*	**Assets commissioned**	18,554	19,465	21,008	29,348	25,375
18	*less*	**Asset disposals**	54	7	328	398	83
20	*plus*	**Lost and found assets adjustment**	–	–	–	–	–
22	*plus*	**Adjustment resulting from asset allocation**	5,012	–	(728)	1,993	614
24		**Total closing RAB value**	267,127	293,278	313,092	338,231	360,545

26 4(ii): Unallocated Regulatory Asset Base

sch ref				Unallocated RAB *		RAB	
28				($000)	($000)	($000)	($000)
29		**Total opening RAB value**			339,474		338,231
30	*less*						
31		**Total depreciation**			14,102		14,002
32	*plus*						
33		**Total revaluations**			10,442		10,410
34	*plus*						
35		Assets commissioned out of WUC	Not Required before DY2026	25,424		25,375	
36		Assets acquired (other than below)	Not Required before DY2026	–		–	
37		Assets acquired from a regulated supplier		–		–	
38		Assets acquired from a related party		–		–	
39		**Assets commissioned**			25,424		25,375
40	*less*						
41		Asset disposals (other than below)		83		83	
42		Asset disposals to a regulated supplier		–		–	
43		Asset disposals to a related party		–		–	
44		**Asset disposals**			83		83
46	*plus*	**Lost and found assets adjustment**			–		–
48	*plus*	**Adjustment resulting from asset allocation**					614
50		**Total closing RAB value**			361,155		360,545

** The 'unallocated RAB' is the total value of those assets used wholly or partially to provide electricity distribution services without any allowance being made for the allocation of costs to services provided by the supplier that are not electricity distribution services. The RAB value represents the value of these assets after applying this cost allocation. Neither value includes works under construction.*

51

Company Name	**Alpine Energy Ltd**
For Year Ended	**31 March 2026**

SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

This schedule requires information on the calculation of the Regulatory Asset Base (RAB) value to the end of this disclosure year. This informs the ROI calculation in Schedule 2.
EDBs must provide explanatory comment on the value of their RAB in Schedule 14 (Mandatory Explanatory Notes). This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref							
52							
53		**4(iii): Calculation of Revaluation Rate and Revaluation of Assets**					
54							
55		CPI_4					1,339
56		CPI_4^{-4}					1,299
57		Revaluation rate (%)					3.08%
58							
59				**Unallocated RAB ***		**RAB**	
60				**($000)**	**($000)**	**($000)**	**($000)**
61		Total opening RAB value		339,474		338,231	
62	*less*	Opening value of fully depreciated, disposed and lost assets		366		181	
63							
64		Total opening RAB value subject to revaluation		339,108		338,049	
65		**Total revaluations**			10,442		10,410
66							
67		**4(iv): Roll Forward of Works Under Construction**					
68				**Unallocated works under construction**		**Allocated works under construction**	
69		**Works under construction—preceding disclosure year**	Not Required before DY2026		10,582		10,931
70	*plus*	WUC capital expenditure	Not Required before DY2026				
71		WUC acquired from a regulated supplier	Not Required before DY2026	–		–	
72		WUC acquired from a related party	Not Required before DY2026	29		29	
73		WUC capital expenditure - other	Not Required before DY2026	33,264		33,264	
74		Total WUC capital expenditure	Not Required before DY2026	33,293		33,293	
75	*less*	WUC capital contributions	Not Required before DY2026	7,212		7,212	
76	*less*	WUC other revenue	Not Required before DY2026	–		–	
77	*less*	Assets commissioned out of WUC	Not Required before DY2026	25,424		25,375	
78	*plus*	Adjustment resulting from asset allocation	Not Required before DY2026			–	
79		**Works under construction - current disclosure year**	Not Required before DY2026		11,238		11,636
80							
81		Highest rate of capitalised finance applied					–
82							

Company Name	**Alpine Energy Ltd**
For Year Ended	**31 March 2026**

SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

This schedule requires information on the calculation of the Regulatory Asset Base (RAB) value to the end of this disclosure year. This informs the ROI calculation in Schedule 2.

EDBs must provide explanatory comment on the value of their RAB in Schedule 14 (Mandatory Explanatory Notes). This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

83 **4(v): Regulatory Depreciation**

sch ref		Unallocated RAB *		RAB	
85		($000)	($000)	($000)	($000)
86	Depreciation - standard	12,033		12,033	
87	Depreciation - no standard life assets	2,069		1,969	
88	Depreciation - modified life assets	–		–	
89	Depreciation - alternative depreciation in accordance with CPP	–		–	
90	**Total depreciation**		14,102		14,002

92 **4(vi): Disclosure of Changes to Depreciation Profiles**

($000 unless otherwise specified)

sch ref	Asset or assets with changes to depreciation*	Reason for non-standard depreciation (text entry)	Depreciation charge for the period (RAB)	Closing RAB value under 'non-standard' depreciation	Closing RAB value under 'standard' depreciation
94	None	Not applicable	Not applicable	Not applicable	Not applicable
95					
96					
97					
98					
99					
100					
101					

102 ** include additional rows if needed*

103 **4(vii): Disclosure by Asset Category**

104 **($000 unless otherwise specified)**

sch ref			Subtransmission lines	Subtransmission cables	Zone substations	Distribution and LV lines	Distribution and LV cables	Distribution substations and transformers	Distribution switchgear	Other network assets	Non-network assets	Total
106		**Total opening RAB value**	12,728	5,787	75,633	84,381	73,531	28,988	26,897	11,681	18,605	338,231
107	*less*	Total depreciation	738	170	3,198	2,858	2,372	1,417	831	449	1,969	14,002
108	*plus*	Total revaluations	392	178	2,325	2,598	2,264	893	828	360	572	10,410
109	*plus*	Assets commissioned	–	47	1,639	7,466	3,155	2,766	3,213	133	6,956	25,375
110	*less*	Asset disposals	–	–	18	8	5	3	7	–	42	83
111	*plus*	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
112	*plus*	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–	614	614
113	*plus*	Asset category transfers	–	–	–	–	–	–	–	–	–	–
114		**Total closing RAB value**	12,382	5,842	76,381	91,579	76,573	31,227	30,100	11,725	24,736	360,545
116		**Asset Life**										
117		Weighted average remaining asset life	28.9	35.8	32.5	38.3	39.8	26.8	33.3	33.0	43.1	(years)
118		Weighted average expected total asset life	51.0	45.0	41.2	53.2	55.7	45.0	40.2	41.9	48.9	(years)

		Company Name	**Alpine Energy Ltd**
		For Year Ended	**31 March 2026**

SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

This schedule requires information on the calculation of the regulatory tax allowance. This information is used to calculate regulatory profit/loss in Schedule 3 (regulatory profit). EDBs must provide explanatory commentary on the information disclosed in this schedule, in Schedule 14 (Mandatory Explanatory Notes).
This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8

sch ref				
7	**5a(i): Regulatory Tax Allowance**			**($000)**
8	**Regulatory profit / (loss) before tax**			26,652
9				
10	*plus* Income not included in regulatory profit / (loss) before tax but taxable	1	*	
11	Expenditure or loss in regulatory profit / (loss) before tax but not deductible	681	*	
12	Amortisation of initial differences in asset values	2,647		
13	Amortisation of revaluations	2,617		
14	**Total**			5,946
15				
16	*less* Total revaluations	10,410		
17	Income included in regulatory profit / (loss) before tax but not taxable	195	*	
18	Discretionary discounts and customer rebates	–		
19	Expenditure or loss deductible but not in regulatory profit / (loss) before tax	–	*	
20	Notional deductible interest	7,025		
21	**Total**			17,629
22				
23	**Regulatory taxable income**			14,969
24				
25	*less* Utilised tax losses	–		
26	Regulatory net taxable income			14,969
27				
28	Corporate tax rate (%)	28%		
29	**Regulatory tax allowance**			4,191
30				
31	* Workings to be provided in Schedule 14			
32	**5a(ii): Disclosure of Permanent Differences**			
33	In Schedule 14, Box 5, provide descriptions and workings of items recorded in the asterisked categories in Schedule 5a(i).			
34	**5a(iii): Amortisation of Initial Difference in Asset Values**			**($000)**
35				
36	Opening unamortised initial differences in asset values	26,471		
37	*less* Amortisation of initial differences in asset values	2,647		
38	*plus* Adjustment for unamortised initial differences in assets acquired	–		
39	*less* Adjustment for unamortised initial differences in assets disposed	–		
40	Closing unamortised initial differences in asset values			23,824
41				
42	Opening weighted average remaining useful life of relevant assets (years)			10
43				

Company Name	**Alpine Energy Ltd**
For Year Ended	**31 March 2026**

SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

This schedule requires information on the calculation of the regulatory tax allowance. This information is used to calculate regulatory profit/loss in Schedule 3 (regulatory profit). EDBs must provide explanatory commentary on the information disclosed in this schedule, in Schedule 14 (Mandatory Explanatory Notes).
This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8

sch ref				
44		**5a(iv): Amortisation of Revaluations**		**($000)**
45				
46		Opening sum of RAB values without revaluations	267,158	
47				
48		Adjusted depreciation	11,385	
49		Total depreciation	14,002	
50		Amortisation of revaluations		2,617
51				
52		**5a(v): Reconciliation of Tax Losses**		**($000)**
53				
54		**Opening tax losses**	–	
55	*plus*	Current period tax losses	–	
56	*less*	Utilised tax losses	–	
57		**Closing tax losses**		–
58		**5a(vi): Calculation of Deferred Tax Balance**		**($000)**
59				
60		**Opening deferred tax**	(21,613)	
61				
62	*plus*	Tax effect of adjusted depreciation	3,188	
63				
64	*less*	Tax effect of tax depreciation	3,966	
65				
66	*plus*	Tax effect of other temporary differences*	31	
67				
68	*less*	Tax effect of amortisation of initial differences in asset values	741	
69				
70	*plus*	Deferred tax balance relating to assets acquired in the disclosure year	–	
71				
72	*less*	Deferred tax balance relating to assets disposed in the disclosure year	(6)	
73				
74	*plus*	Deferred tax cost allocation adjustment	(3)	
75				
76		**Closing deferred tax**		(23,098)
77				
78		**5a(vii): Disclosure of Temporary Differences**		
79		*In Schedule 14, Box 6, provide descriptions and workings of items recorded in the asterisked category in Schedule 5a(vi) (Tax effect of other temporary differences).*		
80				
81		**5a(viii): Regulatory Tax Asset Base Roll-Forward**		
82				**($000)**
83		**Opening sum of regulatory tax asset values**	164,439	
84	*less*	Tax depreciation	14,166	
85	*plus*	Regulatory tax asset value of assets commissioned	23,370	
86	*less*	Regulatory tax asset value of asset disposals	62	
87	*plus*	Lost and found assets adjustment	–	
88	*plus*	Adjustment resulting from asset allocation	605	
89	*plus*	Other adjustments to the RAB tax value	–	
90		**Closing sum of regulatory tax asset values**		174,186

Company Name	Alpine Energy Ltd
For Year Ended	31 March 2026

SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

This schedule provides information on the valuation of related party transactions, in accordance with clause 2.3.6 of this ID determination.
This information is part of audited disclosure information (as defined in clause 1.4 of this ID determination), and so is subject to the assurance report required by clause 2.8.

sch ref		($000)	($000)
7	**5b(i): Summary—Related Party Transactions**		
8	**Total regulatory income**		–
9			
10	**Market value of asset disposals**		–
11			
12	Service interruptions and emergencies	–	
13	Vegetation management	–	
14	Routine and corrective maintenance and inspection	–	
15	Asset replacement and renewal (opex)	–	
16	**Network opex**		–
17	Business support	504	
18	System operations and network support	6	
19	Non-network solutions provided by a related party or third party	–	
20	**Operational expenditure**		510
21	Consumer connection	6	
22	System growth	0	
23	Asset replacement and renewal (capex)	14	
24	Asset relocations	1	
25	Quality of supply	–	
26	Legislative and regulatory	–	
27	Other reliability, safety and environment	5	
28	**Expenditure on non-network assets**		1
29	**Expenditure on assets**		29
30	Cost of financing		–
31	Value of capital contributions		13
32	Value of vested assets		–
33	**Capital Expenditure**		16
34	**Total expenditure**		526
35			
36	**Other related party transactions**		144

37 5b(iii): Total Opex and Capex Related Party Transactions

sch ref	Name of related party	Nature of opex or capex service provided	Total value of transactions ($000)
39	Alpine Energy Directors	Business support	502
40	Timaru District Council	Asset replacement and renewal (capex)	14
41	Timaru District Council	Consumer connection	6
42	Timaru District Council	Expenditure on non-network assets	1
43	Timaru District Council	Other reliability, safety and environment	5
44	Timaru District Council	System growth	0
45	Timaru District Council	Asset relocations	1
46	Timaru District Council	System operations and network support	5
47	Waimate Distict Council	System operations and network support	1
48	Mackenzie District Council	Business support	0
49	LaserGraphix	Business support	2
50			
51			
52			
53			
54	Total value of related party transactions		539

55 ** include additional rows if needed*

Company Name	**Alpine Energy Ltd**
For Year Ended	**31 March 2026**

SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

This schedule is only to be completed if, as at the date of the most recently published financial statements, the weighted average original tenor of the debt portfolio (both qualifying debt and non-qualifying debt) is greater than five years.
This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

5c(i): Qualifying Debt (may be Commission only)

Issuing party	Issue date	Pricing date	Original tenor (in years)	Coupon rate (%)	Book value at issue date (NZD)	Book value at date of financial statements (NZD)	Term Credit Spread Difference	Debt issue cost readjustment
N/A								
Total						–	–	–

5c(ii): Attribution of Term Credit Spread Differential

Gross term credit spread differential		–
Total book value of interest bearing debt		
Leverage	41%	
Average opening and closing RAB values		
Attribution Rate (%)		–
Term credit spread differential allowance		–

Company Name	**Alpine Energy Ltd**
For Year Ended	**31 March 2026**

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

This schedule provides information on the allocation of operational costs. EDBs must provide explanatory comment on their cost allocation in Schedule 14 (Mandatory Explanatory Notes), including on the impact of any reclassifications.
This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

7 **5d(i): Operating Cost Allocations**

sch ref		Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
8			Value allocated ($000s)			
9		Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
10	**Service interruptions and emergencies**					
11	Directly attributable		2,386			
12	Not directly attributable	–	–	–	–	–
13	**Total attributable to regulated service**		2,386			
14	**Vegetation management**					
15	Directly attributable		983			
16	Not directly attributable	–	–	–	–	–
17	**Total attributable to regulated service**		983			
18	**Routine and corrective maintenance and inspection**					
19	Directly attributable		3,060			
20	Not directly attributable	–	–	–	–	–
21	**Total attributable to regulated service**		3,060			
22	**Asset replacement and renewal**					
23	Directly attributable		55			
24	Not directly attributable	–	–	–	–	–
25	**Total attributable to regulated service**		55			
26	**Non-network solutions provided by a related party or third party**					
27	Directly attributable		–			
28	Not directly attributable				–	
29	**Total attributable to regulated service**		–			
30	**System operations and network support**					
31	Directly attributable		11,270			
32	Not directly attributable	–	–	–	–	–
33	**Total attributable to regulated service**		11,270			
34	**Business support**					
35	Directly attributable		1,017			
36	Not directly attributable	–	15,311	810	16,121	–
37	**Total attributable to regulated service**		16,328			
38						
39	**Operating costs directly attributable**		18,772			
40	**Operating costs not directly attributable**	–	15,311	810	16,121	–
41	**Operational expenditure**		34,082			
42						

Company Name	Alpine Energy Ltd
For Year Ended	31 March 2026

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

This schedule provides information on the allocation of operational costs. EDBs must provide explanatory comment on their cost allocation in Schedule 14 (Mandatory Explanatory Notes), including on the impact of any reclassifications.
This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref		
43	**5d(ii): Other Cost Allocations**	
44	**Pass through and recoverable costs**	**($000)**
45	**Pass through costs**	
46	Directly attributable	17,582
47	Not directly attributable	–
48	**Total attributable to regulated service**	17,582
49	**Recoverable costs**	
50	Directly attributable	95
51	Not directly attributable	–
52	**Total attributable to regulated service**	95
53		

sch ref					
54	**5d(iii): Changes in Cost Allocations* †**				
55				**($000)**	
56	**Change in cost allocation 1**			**CY-1**	**Current Year (CY)**
57	Cost category	N/A - no changes to cost allocations in the current year	Original allocation		
58	Original allocator or line items		New allocation		
59	New allocator or line items		Difference	–	–
60					
61	Rationale for change				
62					
63					
64				**($000)**	
65	**Change in cost allocation 2**			**CY-1**	**Current Year (CY)**
66	Cost category		Original allocation		
67	Original allocator or line items		New allocation		
68	New allocator or line items		Difference	–	–
69					
70	Rationale for change				
71					
72					
73				**($000)**	
74	**Change in cost allocation 3**			**CY-1**	**Current Year (CY)**
75	Cost category		Original allocation		
76	Original allocator or line items		New allocation		
77	New allocator or line items		Difference	–	–
78					
79	Rationale for change				
80					
81					

82 ** a change in cost allocation must be completed for each cost allocator change that has occurred in the disclosure year. A movement in an allocator metric is not a change in allocator or component.*

83 *† include additional rows if needed*

Company Name: **Alpine Energy Ltd**
For Year Ended: **31 March 2026**

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

This schedule requires information on the allocation of asset values. This information supports the calculation of the RAB value in Schedule 4.
EDBs must provide explanatory comment on their cost allocation in Schedule 14 (Mandatory Explanatory Notes), including on the impact of any changes in asset allocations. This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

5e(i): Regulated Service Asset Values

sch ref		Value allocated ($000s) Electricity distribution services
10	**Subtransmission lines**	
11	Directly attributable	12,382
12	Not directly attributable	–
13	**Total attributable to regulated service**	12,382
14	**Subtransmission cables**	
15	Directly attributable	5,842
16	Not directly attributable	–
17	**Total attributable to regulated service**	5,842
18	**Zone substations**	
19	Directly attributable	76,382
20	Not directly attributable	
21	**Total attributable to regulated service**	76,382
22	**Distribution and LV lines**	
23	Directly attributable	91,579
24	Not directly attributable	–
25	**Total attributable to regulated service**	91,579
26	**Distribution and LV cables**	
27	Directly attributable	76,573
28	Not directly attributable	–
29	**Total attributable to regulated service**	76,573
30	**Distribution substations and transformers**	
31	Directly attributable	31,227
32	Not directly attributable	–
33	**Total attributable to regulated service**	31,227
34	**Distribution switchgear**	
35	Directly attributable	30,100
36	Not directly attributable	–
37	**Total attributable to regulated service**	30,100
38	**Other network assets**	
39	Directly attributable	11,725
40	Not directly attributable	–
41	**Total attributable to regulated service**	11,725
42	**Non-network assets**	
43	Directly attributable	4,018
44	Not directly attributable	20,717
45	**Total attributable to regulated service**	24,735
46		
47	**Regulated service asset value directly attributable**	339,828
48	**Regulated service asset value not directly attributable**	20,717
49	**Total closing RAB value**	360,545

5e(ii): Changes in Asset Allocations* †

sch ref				($000) CY-1	($000) Current Year (CY)
53	**Change in asset value allocation 1**				
54	Asset category	N/A - no changes to asset allocations in the current year	Original allocation		
55	Original allocator or line items		New allocation		
56	New allocator or line items		Difference	–	–
58	Rationale for change				

sch ref				($000) CY-1	($000) Current Year (CY)
62	**Change in asset value allocation 2**				
63	Asset category		Original allocation		
64	Original allocator or line items		New allocation		
65	New allocator or line items		Difference	–	–
67	Rationale for change				

sch ref				($000) CY-1	($000) Current Year (CY)
71	**Change in asset value allocation 3**				
72	Asset category		Original allocation		
73	Original allocator or line items		New allocation		
74	New allocator or line items		Difference	–	–
76	Rationale for change				

79 ** a change in asset allocation must be completed for each allocator or component change that has occurred in the disclosure year. A movement in an allocator metric is not a change in allocator or compone*

80 *† include additional rows if needed*

Company Name	**Alpine Energy Ltd**
For Year Ended	**31 March 2026**

SCHEDULE 6a: REPORT ON CAPITAL EXPENDITURE FOR THE DISCLOSURE YEAR

This schedule requires a breakdown of capital expenditure on assets incurred in the disclosure year, including any assets in respect of which capital contributions are received, but excluding assets that are vested assets. Information on expenditure on assets must be provided on an accounting accruals basis and must exclude finance costs.
EDBs must provide explanatory comment on their expenditure on assets in Schedule 14 (Explanatory Notes to Templates).
This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref				
7		**6a(i): Expenditure on Assets**	**($000)**	**($000)**
8		Consumer connection		7,588
9		System growth		2,624
10		Asset replacement and renewal		14,371
11		Asset relocations		974
12		Reliability, safety and environment:		
13		Quality of supply	0	
14		Legislative and regulatory	23	
15		Other reliability, safety and environment	4,353	
16		**Total reliability, safety and environment**		4,376
17		**Expenditure on network assets**		29,934
18		Expenditure on non-network assets		3,359
19				
20		**Expenditure on assets**		33,292
21	*plus*	Cost of financing		–
22	*less*	Value of capital contributions		7,212
23	*plus*	Value of vested assets		–
24				
25		**Capital expenditure**		26,080
26		**6a(ii): Subcomponents of Expenditure on Assets (where known)**		**($000)**
27		Energy efficiency and demand side management, reduction of energy losses		
28		Overhead to underground conversion		820
29		Research and development		–
31		**6a(iii): Consumer Connection**		
32		*Consumer types defined by EDB**	**($000)**	**($000)**
33		CC - Commercial	4,996	
34		CC - HV alterations	377	
35		CC - Irrigation	200	
36		CC - LV alterations	93	
		CC - Residential	1,258	
37		CC - Subdivision	664	
38		** include additional rows if needed*		
39		**Consumer connection expenditure**		7,588
40				
41	*less*	Capital contributions funding consumer connection expenditure	6,931	
42		**Consumer connection less capital contributions**		657
43		**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset Replacement and**
44			**System Growth**	**Renewal**
45			**($000)**	**($000)**
46		Subtransmission	–	–
47		Zone substations	580	44
48		Distribution and LV lines	7	8,586
49		Distribution and LV cables	1,300	2,874
50		Distribution substations and transformers	41	2,260
51		Distribution switchgear	394	548
52		Other network assets	301	60
53		**System growth and asset replacement and renewal expenditure**	2,624	14,371
54	*less*	Capital contributions funding system growth and asset replacement and renewal	4	207
55		**System growth and asset replacement and renewal less capital contributions**	2,621	14,164
56				
57		**6a(v): Asset Relocations**		
58		*Project or programme**	**($000)**	**($000)**
59		Pages Rd to Centennial Park Undergrounding	703	
60				
61			–	
62			–	
63			–	
64		** include additional rows if needed*		
65		All other projects or programmes - asset relocations	271	
66		**Asset relocations expenditure**		974
67	*less*	Capital contributions funding asset relocations	71	
68		**Asset relocations less capital contributions**		903

Company Name	Alpine Energy Ltd	
For Year Ended	31 March 2026	

SCHEDULE 6a: REPORT ON CAPITAL EXPENDITURE FOR THE DISCLOSURE YEAR

This schedule requires a breakdown of capital expenditure on assets incurred in the disclosure year, including any assets in respect of which capital contributions are received, but excluding assets that are vested assets. Information on expenditure on assets must be provided on an accounting accruals basis and must exclude finance costs.
EDBs must provide explanatory comment on their expenditure on assets in Schedule 14 (Explanatory Notes to Templates).
This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref			($000)	($000)
69				
70	**6a(vi): Quality of Supply**			
71		*Project or programme**	($000)	($000)
72		N/A	–	
73			–	
74			–	
75			–	
76			–	
77		** include additional rows if needed*		
78		All other projects programmes - quality of supply	0	
79		**Quality of supply expenditure**		0
80	*less*	Capital contributions funding quality of supply	0	
81		**Quality of supply less capital contributions**		0
82	**6a(vii): Legislative and Regulatory**			
83		*Project or programme**	($000)	($000)
84		N/A	–	
85			–	
86			–	
87			–	
88			–	
89		** include additional rows if needed*		
90		All other projects or programmes - legislative and regulatory	23	
91		**Legislative and regulatory expenditure**		23
92	*less*	Capital contributions funding legislative and regulatory	–	
93		**Legislative and regulatory less capital contributions**		23
94	**6a(viii): Other Reliability, Safety and Environment**			
95		*Project or programme**	($000)	($000)
96		Hunt Street Ring Main Unit install	1,033	
97				
98				
99				
100				
101		** include additional rows if needed*		
102		All other projects or programmes - other reliability, safety and environment	3,320	
103		**Other reliability, safety and environment expenditure**		4,353
104	*less*	Capital contributions funding other reliability, safety and environment	–	
105		**Other reliability, safety and environment less capital contributions**		4,353
106				
107	**6a(ix): Non-Network Assets**			
108	**Routine expenditure**			
109		*Project or programme**	($000)	($000)
110		Plant & Equipment	2,775	
111		Land & Building	78	
112		Computer & Software	504	
113				
114				
115		** include additional rows if needed*		
116		All other projects or programmes - routine expenditure	–	
117		**Routine expenditure**		3,356
118	**Atypical expenditure**			
119		*Project or programme**	($000)	($000)
120		N/A	–	
121			–	
122			–	
123			–	
124			–	
125		** include additional rows if needed*		
126		All other projects or programmes - atypical expenditure	2	
127		**Atypical expenditure**		2
128				
129		**Expenditure on non-network assets**		3,359

Company Name	Alpine Energy Ltd	
For Year Ended	31 March 2026	

SCHEDULE 6b: REPORT ON OPERATIONAL EXPENDITURE FOR THE DISCLOSURE YEAR

This schedule requires a breakdown of operational expenditure incurred in the disclosure year.
EDBs must provide explanatory comment on their operational expenditure in Schedule 14 (Explanatory notes to templates). This includes explanatory comment on any atypical operational expenditure and assets replaced or renewed as part of asset replacement and renewal operational expenditure, and additional information on insurance.
This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref			
7	**6b(i): Operational Expenditure** *Not Required before DY2026*	**($000)**	**($000)**
8	Service interruptions and emergencies:		
9	Vegetation-related	–	
10	Other	2,386	
11	**Total service interruptions and emergencies**	2,386	
12	Vegetation management:		
13	Assessment and notification costs	52	
14	Felling or trimming vegetation - in-zone	931	
15	Felling or trimming vegetation - out-of-zone	1	
16	Other	–	
17	**Total vegetation management**	983	
18			
19	Routine and corrective maintenance and inspection:	3,060	
20	Asset replacement and renewal	55	
21	**Network opex**		6,484
22	Non-network solutions provided by a related party or third party	–	
23	System operations and network support	11,270	
24	Business support	16,328	
25	**Non-network opex**		27,598
26			
27	**Operational expenditure**		34,082
28	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
29	Energy efficiency and demand side management, reduction of energy losses		–
30	Direct billing*		–
31	Research and development		–
32	Insurance		608
33	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**Alpine Energy Ltd**
For Year Ended	**31 March 2026**

SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

This schedule compares actual revenue and expenditure to the previous forecasts that were made for the disclosure year. Accordingly, this schedule requires the forecast revenue and expenditure information from previous disclosures to be inserted.
EDBs must provide explanatory comment on the variance between actual and target revenue and forecast expenditure in Schedule 14 (Mandatory Explanatory Notes).
This information is part of the audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8. For the purpose of this audit, target revenue and forecast expenditures only need to be verified back to previous disclosures.

sch ref				
7	**7(i): Revenue**	**Target ($000) [1]**	**Actual ($000)**	**% variance**
8	Line charge revenue	81,625	81,946	0.4%
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	4,688	7,588	62%
11	System growth	3,651	2,624	(28%)
12	Asset replacement and renewal	16,628	14,371	(14%)
13	Asset relocations	750	974	30%
14	Reliability, safety and environment:			
15	Quality of supply	1,137	0	(100%)
16	Legislative and regulatory	–	23	–
17	Other reliability, safety and environment	3,714	4,353	17%
18	**Total reliability, safety and environment**	4,851	4,376	(10%)
19	**Expenditure on network assets**	30,568	29,934	(2%)
20	Expenditure on non-network assets	5,809	3,359	(42%)
21	Expenditure on assets	36,377	33,292	(8%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	2,181	2,386	9%
24	Vegetation management	1,000	983	(2%)
25	Routine and corrective maintenance and inspection	4,392	3,060	(30%)
26	Asset replacement and renewal	25	55	119%
27	**Network opex**	7,598	6,484	(15%)
28	Non-network solutions provided by a related party or third party	–	–	–
29	System operations and network support	6,307	11,270	79%
30	Business support	22,802	16,328	(28%)
31	**Non-network opex**	29,109	27,598	(5%)
32	**Operational expenditure**	36,707	34,082	(7%)
33	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
34	Energy efficiency and demand side management, reduction of energy losses	–	–	–
35	Overhead to underground conversion	–	820	–
36	Research and development	–	–	–
37				
38	**7(v): Subcomponents of Operational Expenditure (where known)**			
39	Energy efficiency and demand side management, reduction of energy losses	–	–	–
40	Direct billing	–	–	–
41	Research and development	–	–	–
42	Insurance	703	608	(14%)
43				

44 *1 From the nominal dollar target revenue for the disclosure year disclosed under clause 2.4.3(3) of this determination*

45 *2 From the CY+1 nominal dollar expenditure forecasts disclosed in accordance with clause 2.6.6 for the forecast period starting at the beginning of the disclosure year (the second to last disclosure of Schedules 11a and 11b)*

Company Name	**Alpine Energy Ltd**
For Year Ended	**31 March 2026**
Network / Sub-Network Name	**Alpine Energy Limited**

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the EDB in its pricing schedules. Information is also required on the number of ICPs that are included in each consumer group or price category code, and the energy delivered to these ICPs.
EDBs should feel free to adjust the page break of this schedule to assist with readibility if needed.

sch ref

8 **8(i): Billed Quantities by Price Component**

sch ref	Consumer group name or price category code	Standardised connection types	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)
15	LOWHCA	Residential	Standard	2,310	14,302
16	LOWLCA	Residential	Standard	10,908	60,391
17	LOWUHCA	Residential	Standard	30	162
18	LOWULCA	Residential	Standard	71	401
19	015HCA	Residential	Standard	5,962	60,136
20	015LCA	Residential	Standard	11,476	99,083
21	015UHCA	Residential	Standard	46	658
22	015ULCA	Residential	Standard	56	428
23	030HCA	Commercial	Standard	9	84
24	030LCA	Commercial	Standard	5	33
25	030UHCA	Commercial	Standard	2	54
26	030ULCA	Commercial	Standard	3	64
27	045HCA	Commercial	Standard	526	11,079
28	045LCA	Commercial	Standard	743	21,534
29	045UHCA	Commercial	Standard	14	485
30	045ULCA	Commercial	Standard	17	407
31	360LCA	Commercial	Standard	(9)	–
32	ASSHCA	Industrial	Standard	1,309	126,859
33	ASSLCA	Industrial	Standard	419	43,134
34	TOU400HCA	Industrial	Standard	37	22,381
35	TOU400LCA	Industrial	Standard	102	95,127
36	TOU11HCA	Industrial	Standard	6	33,669
37	TOU11LCA	Industrial	Standard	6	28,560
38	Individual Direct Billed	Industrial	Non-standard	9	199,162
39	*Add extra rows for additional consumer groups or price category codes as necessary*				
40			**Standard consumer totals**	34,048	619,031
41			**Non-standard consumer totals**	9	199,162
42			**Total for all consumers**	34,057	818,193

Billed quantities by price component

sch ref	Consumer group name or price category code	Daily fixed charge - $/day		her charge [see EDB defined price component bel		er charge [see EDB defined price component be		r charge [see EDB defined price component b	
	EDB defined price component			Variable Day charge - $/kWh		Variable Night charge - $/kWh		Demand Charge - $/kW/day	
		Distribution billed quantity	**Transmission billed quantity**	**Distribution billed quantity**	**Transmission billed quantity**	**Distribution billed quantity**	**Transmission billed quantity**	**Distribution billed quantity**	**Transmission billed quantity**
15	LOWHCA	2,310	2,310	10,336,469	10,336,469	3,965,079	3,965,079	–	–
16	LOWLCA	10,908	10,908	43,689,015	43,689,015	16,701,809	16,701,809	–	–
17	LOWUHCA	30	30	117,235	117,235	45,236	45,236	–	–
18	LOWULCA	71	71	290,167	290,167	111,139	111,139	–	–
19	015HCA	5,962	5,962	43,508,720	43,508,720	16,627,388	16,627,388	–	–
20	015LCA	11,476	11,476	71,686,730	71,686,730	27,395,958	27,395,958	–	–
21	015UHCA	46	46	476,046	476,046	181,927	181,927	–	–
22	015ULCA	56	56	309,645	309,645	118,334	118,334	–	–
23	030HCA	9	9	60,791	60,791	23,232	23,232	–	–
24	030LCA	5	5	23,948	23,948	9,152	9,152	–	–
25	030UHCA	2	2	38,946	38,946	14,884	14,884	–	–
26	030ULCA	3	3	46,468	46,468	17,758	17,758	–	–
27	045HCA	526	526	8,015,489	8,015,489	3,063,217	3,063,217	–	–
28	045LCA	743	743	15,579,774	15,579,774	5,954,001	5,954,001	–	–
29	045UHCA	14	14	351,005	351,005	134,141	134,141	–	–
30	045ULCA	17	17	294,808	294,808	112,664	112,664	–	–
31	360LCA	(9)	(9)	–	–	–	–	–	–
32	ASSHCA	1,309	1,309	91,419,322	91,419,322	35,439,605	35,439,605	114,540	114,540
33	ASSLCA	419	419	31,103,041	31,103,041	12,030,637	12,030,637	40,982	40,982
34	TOU400HCA	37	37	15,650,567	15,650,567	6,730,497	6,730,497	8,149	8,149
35	TOU400LCA	102	102	65,817,725	65,817,725	29,308,990	29,308,990	23,702	23,702
36	TOU11HCA	6	6	23,737,261	23,737,261	9,931,765	9,931,765	8,247	8,247
37	TOU11LCA	6	6	19,073,357	19,073,357	9,486,808	9,486,808	9,344	9,344
38	Individual Direct Billed	9	9	139,414	139,414	59,749	59,749	–	–
40	Standard consumer totals	34,048	34,048	441,626,529	441,626,529	177,404,221	177,404,221	204,964	204,964
41	Non-standard consumer totals	9	9	139,414	139,414	59,749	59,749	–	–
42	Total for all consumers	34,057	34,057	441,765,943	441,765,943	177,463,969	177,463,969	204,964	204,964

Add extra columns for additional billed quantities by price component as necessary

Company Name	Alpine Energy Ltd
For Year Ended	31 March 2026
Network / Sub-Network Name	Alpine Energy Limited

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the EDB in its pricing schedules. Information is also required on the number of ICPs that are included in each consumer group or price category code, and the energy delivered to these ICPs.
EDBs should feel free to adjust the page break of this schedule to assist with readibility if needed.

8(ii): Line Charge Revenues ($000) by Price Component

				Consumer discounts ($000)				
			Standardised price component	[Select one]				
			EDB defined price component	NA				
Consumer group name or price category code	Standardised connection types	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Total distribution line charge revenue	Total transmission line charge revenue
LOWHCA	Residential	Standard	$2,435	–	–	–	$2,140	$294
LOWLCA	Residential	Standard	$9,914	–	–	–	$8,670	$1,244
LOWUHCA	Residential	Standard	$29	–	–	–	$25	$4
LOWULCA	Residential	Standard	$67	–	–	–	$58	$9
015HCA	Residential	Standard	$8,511	–	–	–	$7,650	$860
015LCA	Residential	Standard	$14,964	–	–	–	$13,307	$1,657
015UHCA	Residential	Standard	$70	–	–	–	$62	$8
015ULCA	Residential	Standard	$73	–	–	–	$64	$9
030HCA	Commercial	Standard	$27	–	–	–	$25	$2
030LCA	Commercial	Standard	$14	–	–	–	$13	$1
030UHCA	Commercial	Standard	$6	–	–	–	$6	$1
030ULCA	Commercial	Standard	$8	–	–	–	$8	$1
045HCA	Commercial	Standard	$2,488	–	–	–	$2,318	$169
045LCA	Commercial	Standard	$3,272	–	–	–	$3,033	$239
045UHCA	Commercial	Standard	$68	–	–	–	$63	$5
045ULCA	Commercial	Standard	$73	–	–	–	$67	$7
360LCA	Commercial	Standard	($2)	–	–	–	($2)	($1)
ASSHCA	Industrial	Standard	$16,591	–	–	–	$15,664	$926
ASSLCA	Industrial	Standard	$5,238	–	–	–	$4,925	$313
TOU400HCA	Industrial	Standard	$2,196	–	–	–	$2,126	$71
TOU400LCA	Industrial	Standard	$6,235	–	–	–	$6,031	$204
TOU11HCA	Industrial	Standard	$2,138	–	–	–	$2,083	$55
TOU11LCA	Industrial	Standard	$1,993	–	–	–	$1,930	$63
Individual Direct Billed	Industrial	Non-standard	$5,540	–	–	–	$3,376	$2,164
Add extra rows for additional consumer groups or price category codes as necessary								
		Standard consumer totals	$76,406	–	–	–	$70,265	$6,141
		Non-standard consumer totals	$5,540	–	–	–	$3,376	$2,164
		Total for all consumers	$81,946	–	–	–	$73,641	$8,305

	Line charge revenues ($000) by price component											
Standardised price component	Daily fixed charge - $/day			Other charge [see EDB defined price component below]			Other charge [see EDB defined price component below]			Other charge [see EDB defined price component below]		
EDB defined price component				Variable Day charge - $/kWh			Variable Night charge - $/kWh			Demand Charge - $/kW/day		
Consumer group name or price category code	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)
LOWHCA	$632	–	$632	$1,096	$213	$1,309	$411	$82	$493	–	–	–
LOWLCA	$2,986	–	$2,986	$4,138	$900	$5,038	$1,545	$344	$1,889	–	–	–
LOWUHCA	$8	–	$8	$13	$3	$15	$5	$1	$6	–	–	–
LOWULCA	$19	–	$19	$28	$7	$34	$10	$3	$13	–	–	–
015HCA	$6,785	$860	$7,645	$653	–	$653	$213	–	$213	–	–	–
015LCA	$11,881	$1,657	$13,538	$1,075	–	$1,075	$351	–	$351	–	–	–
015UHCA	$53	$8	$61	$7	–	$7	$2	–	$2	–	–	–
015ULCA	$58	$9	$67	$5	–	$5	$2	–	$2	–	–	–
030HCA	$23	$2	$26	$1	–	$1	$0	–	$0	–	–	–
030LCA	$12	$1	$13	$0	–	$0	$0	–	$0	–	–	–
030UHCA	$5	$1	$5	$1	–	$1	$0	–	$0	–	–	–
030ULCA	$7	$1	$7	$1	–	$1	$0	–	$0	–	–	–
045HCA	$2,159	$169	$2,328	$120	–	$120	$39	–	$39	–	–	–
045LCA	$2,723	$239	$2,962	$234	–	$234	$76	–	$76	–	–	–
045UHCA	$56	$5	$61	$5	–	$5	$2	–	$2	–	–	–
045ULCA	$61	$7	$67	$4	–	$4	$1	–	$1	–	–	–
360LCA	($2)	($1)	($2)	–	–	–	–	–	–	–	–	–
ASSHCA	$2,439	$512	$2,951	$1,371	–	$1,371	$454	–	$454	$11,401	$414	$11,815
ASSLCA	$705	$164	$869	$467	–	$467	$154	–	$154	$3,600	$148	$3,748
TOU400HCA	$61	$18	$79	$203	–	$203	$73	–	$73	$1,789	$53	$1,841
TOU400LCA	$149	$49	$198	$856	–	$856	$317	–	$317	$4,710	$155	$4,865
TOU11HCA	$10	$1	$11	$309	–	$309	$107	–	$107	$1,658	$54	$1,711
TOU11LCA	$8	$1	$9	$247	–	$247	$101	–	$101	$1,573	$62	$1,635
Individual Direct Billed	$3,376	$2,164	$5,540	–	–	–	–	–	–	–	–	–
Standard consumer totals	$30,838	$3,704	$34,542	$10,833	$1,122	$11,955	$3,864	$429	$4,293	$24,730	$886	$25,616
Non-standard consumer totals	$3,376	$2,164	$5,540	–	–	–	–	–	–	–	–	–
Total for all consumers	$34,214	$5,868	$40,082	$10,833	$1,122	$11,955	$3,864	$429	$4,293	$24,730	$886	$25,616

Add extra columns for additional line charge revenues by price component as necessary

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	9

Company Name	**Alpine Energy Ltd**
For Year Ended	**31 March 2026**
Network / Sub-network Name	**Alpine Energy Limited**

SCHEDULE 9a: ASSET REGISTER

This schedule requires a summary of the quantity of assets that make up the network, by asset category and asset class. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

9a: Asset Register

8	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
9	All	Overhead Line	Concrete poles / steel structure	No.	25,935	25,984	49	3
10	All	Overhead Line	Wood poles	No.	18,491	17,818	(673)	3
11	All	Overhead Line	Other pole types	No.	263	167	(96)	3
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	250	252	2	3
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	0	0	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	34	34	0	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	N/A
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	N/A
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	N/A
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	N/A
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	28	26	(2)	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	2	2	–	4
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	2	2	–	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	6	6	–	4
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	113	95	(18)	4
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	7	7	–	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	26	27	1	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	188	188	–	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	8	8	–	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	32	31	(1)	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2,919	2,903	(16)	3
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	7	7	0	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	399	327	(71)	2
39	HV	Distribution Cable	Distribution UG PILC	km	135	129	(5)	2
40	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	N/A
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	60	61	1	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	4	4	–	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	6,976	6,715	(261)	2
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	73	73	–	4
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	490	507	17	4
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	5,069	5,067	(2)	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	1,141	1,158	17	4
48	HV	Distribution Transformer	Voltage regulators	No.	69	70	1	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	N/A
50	LV	LV Line	LV OH Conductor	km	347	340	(7)	3
51	LV	LV Cable	LV UG Cable	km	381	362	(19)	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	–	N/A
53	LV	Connections	OH/UG consumer service connections	No.	34,938	32,474	(2,464)	3
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	507	502	(5)	3
55	All	SCADA and communications	SCADA and communications equipment operating as a single syster	Lot	629	665	36	3
56	All	Capacitor Banks	Capacitors including controls	No	11	19	8	4
57	All	Load Control	Centralised plant	Lot	7	6	(1)	4
58	All	Load Control	Relays	No	–	–	–	N/A
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name	Alpine Energy Ltd
For Year Ended	31 March 2026
Network / Sub-network Name	Alpine Energy Limited

SCHEDULE 9b: ASSET AGE PROFILE

This schedule requires a summary of the age profile (based on year of installation) of the assets that make up the network, by asset category and asset class. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

9b: Asset Age Profile

8 Disclosure Year (year ended)

Number of assets at disclosure year end by installation date

9	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.	–	193	3,235	5,191	3,680	2,396	1,531	139	221	245	429	447	808	304	308	302	325	318	141	383	482	386	315	367	229	281	321	480	457	494	545	443	250	208	1	–	129	25,984		3
11	All	Overhead Line	Wood poles	No.	–	7	2,261	1,422	1,848	1,612	1,701	169	171	432	448	395	548	333	498	695	628	350	231	363	345	487	278	240	151	117	161	199	187	258	244	327	175	147	–	–	390	17,818		3
12	All	Overhead Line	Other pole types	No.	–	–	33	45	29	17	13	6	–	–	2	1	–	–	–	2	–	2	2	2	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	12	167		3
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	4	36	40	11	58	5	–	8	14	0	0	1	–	–	–	1	0	0	21	31	0	12	0	0	4	3	–	–	0	0	–	–	–	–	2	252		3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0	–	–	–	–	–	–	–	0	–	–	–	–	–	–	–	–	–	–	–	0		N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	0	0	1	–	–	–	0	0	23	–	–	–	–	–	0	0	–	0	–	2	3	1	0	0	3	0	0	–	–	–	–	–	–	34		4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	–	–	3	1	2	5	1	–	–	–	–	1	1	–	–	–	–	–	4	1	–	–	–	–	1	1	–	1	–	–	1	–	1	–	–	–	2	26		4
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0	1	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	2		4
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	2		4
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	6	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	6		4
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	–	7	8	6	6	–	–	–	–	–	–	–	–	1	–	1	3	–	9	8	6	1	12	1	7	3	1	6	9	–	–	–	–	–	–	95		4
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	6	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7		4
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	–	–	3	4	–	–	–	–	2	–	–	–	–	–	1	–	2	1	3	1	3	2	–	1	1	–	–	3	–	–	–	–	–	–	27		4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	–	–	24	15	–	–	–	–	12	14	14	–	–	8	5	–	24	25	8	5	–	2	5	–	–	–	–	–	9	18	–	–	–	–	188		4
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4	–	–	–	–	–	–	2	–	–	–	1	1	–	–	–	–	–	–	–	–	–	8		4
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	–	–	5	–	2	–	–	–	–	2	–	2	–	2	1	1	3	–	1	1	–	–	–	2	–	–	3	3	1	1	–	1	–	–	–	31		4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	6	–	833	469	343	237	151	2	28	34	73	62	132	35	46	54	58	36	16	29	39	37	28	29	12	9	10	14	25	20	8	4	6	4	–	–	13	2,903		3
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
38	HV	Distribution Line	SWER conductor	km	–	–	–	–	7	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7		4
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	1	1	2	8	7	1	5	14	11	5	11	19	14	17	13	10	9	11	11	5	16	14	17	24	13	6	13	15	21	6	4	1	–	–	0	327		2
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	7	38	52	28	2	0	0	0	0	1	0	0	0	0	0	–	0	–	–	–	–	–	–	–	–	–	0	–	–	–	–	–	–	–	129		2
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionaliser	No.	–	–	–	–	–	–	4	2	–	–	–	4	1	1	–	–	5	2	3	–	8	5	1	2	6	4	1	6	–	2	1	3	–	–	–	–	–	61		4
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4	4		4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	2	1	329	344	318	259	257	27	60	76	134	109	159	115	151	235	237	194	148	232	231	244	327	219	571	330	216	249	194	199	152	166	155	66	–	–	9	6,715		2
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	1	1	2	1	1	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	1	3	7	7	6	7	12	12	9	2	–	–	–	–	73		4
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	6	38	22	46	2	4	3	17	8	4	11	8	6	10	14	10	6	2	6	25	28	23	35	8	18	28	17	33	15	36	18	–	–	–	507		4
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	1	21	336	580	515	376	497	59	127	132	140	142	74	134	147	109	226	94	76	104	76	162	128	94	73	117	61	61	75	82	80	57	47	41	–	–	23	5,067		4
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	1	9	36	128	93	27	7	25	34	45	24	47	51	38	63	59	9	10	29	18	35	47	47	39	34	35	16	40	35	32	18	17	6	–	–	4	1,158		4
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	–	–	–	–	2	2	–	–	–	4	10	21	2	5	–	4	6	–	4	–	2	4	3	–	–	–	–	–	1	–	–	–	70		4
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
51	LV	LV Line	LV OH Conductor	km	0	–	54	116	98	38	18	1	1	1	1	1	0	1	0	1	1	1	0	0	0	0	1	0	0	1	1	0	0	0	0	1	1	0	–	–	1	340		3
52	LV	LV Cable	LV UG Cable	km	–	–	0	12	70	87	65	3	4	4	4	7	7	8	8	5	7	5	3	0	1	1	3	8	4	7	7	4	7	7	7	3	2	1	–	–	1	362		3
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
54	LV	Connections	OH/UG consumer service connections	No.	1	–	–	1	2	2	6	793	11	9	861	23	18	37	19	23	29	31	18	21	20	20	21	15	23	36	11	40	102	305	347	213	186	67	–	–	29,163	32,474		4
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	–	–	7	–	–	–	12	–	22	17	10	1	9	4	14	129	36	54	30	7	41	24	7	4	5	–	2	17	–	8	–	–	–	42	502		3
56	All	SCADA and communications	SCADA and communications equipment operating as a single syst	Lot	–	–	–	–	–	–	55	–	–	–	–	–	–	–	–	–	–	–	5	47	21	3	18	38	16	42	5	12	72	59	88	33	62	6	–	–	83	665		3
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	6	1	–	1	1	–	–	–	–	–	–	1	–	2	–	–	–	6	–	–	–	1	19		4
58	All	Load Control	Centralised plant	Lot	–	–	–	–	1	–	–	–	–	–	1	–	1	–	–	–	–	–	–	–	–	–	–	–	–	2	–	1	–	–	–	–	–	–	–	–	–	6		4
59	All	Load Control	Relays	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A

Company Name	**Alpine Energy Ltd**
For Year Ended	**31 March 2026**
Network / Sub-network Name	**Alpine Energy Limited**

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

This schedule requires a summary of the key characteristics of the overhead line and underground cable network. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

9 **9c: Overhead Lines and Underground Cables**

10

Main equipment involved

Subtransmission lines
Subtransmission cables
Subtransmission other
Distribution lines (excluding LV)
Distribution cables (excluding LV)
Distribution other (excluding LV)
Total

sch ref		Overhead (km)	Underground (km)	Total circuit length (km)
11	**Circuit length by operating voltage (at year end)**			
12	> 66kV	1		1
13	50kV & 66kV			–
14	33kV	252	34	286
15	SWER (all SWER voltages)		7	7
16	22kV (other than SWER)	145	17	162
17	6.6kV to 11kV (inclusive—other than SWER)	2,748	471	3,219
18	Low voltage (< 1kV)	365	381	746
19	**Total circuit length (for supply)**	3,511	910	4,421
20				
21	Dedicated street lighting circuit length (km)			–
22	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			82
23				

sch ref		Circuit length (km)	(% of total overhead length)
24	**Overhead circuit length by terrain (at year end)**		
25	Urban	265	8%
26	Rural	2,917	83%
27	Remote only	234	7%
28	Rugged only	86	2%
29	Remote and rugged	9	0%
30	Unallocated overhead lines		–
31	**Total overhead length**	3,511	100%
32			

sch ref		Circuit length (km)	(% of total circuit length)
33			
34	Length of circuit within 10km of coastline or geothermal areas (where known)	1,816	41%
35			

sch ref		Total newly identified throughout the disclosure year	Total remaining at high risk at the disclosure year-end	
36				
37	Number of overhead circuit sites at high risk from vegetation damage	753	7,930	*Not required before DY2026*
38				

39 **Breakdown of overhead circuit sites at high risk from vegetation damage at disclosure year-end**

sch ref	Category of overhead circuit site	Number of overhead circuit sites at high risk from vegetation damage at disclosure year-end	Number of overhead circuit sites involving critical assets at disclosure year-end	
40				
41	Single tree - Urban	987	381	*Not required before DY2026*
42	Single tree - Rural	5,955	4,112	*Not required before DY2026*
43	Row of trees	988	817	*Not required before DY2026*
44				*Not required before DY2026*
45				*Not required before DY2026*
46				*Not required before DY2026*
47	**Total number of sites**	7,930	5,310	*Not required before DY2026*

48 ** Insert new rows in table above Total line as necessary*

Company Name **Alpine Energy Ltd**
For Year Ended **31 March 2026**

SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

This schedule requires information concerning embedded networks owned by an EDB that are embedded in another EDB's network or in another embedded network.

sch ref

	Location *	Average number of ICPs in disclosure year	Line charge revenue ($000)
8			
9	N/A	–	–
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			

26 ** Extend embedded distribution networks table as necessary to disclose each embedded network owned by the EDB which is embedded in another EDB's network or in another embedded network*

Company Name	**Alpine Energy Ltd**
For Year Ended	**31 March 2026**
Network / Sub-network Name	**Alpine Energy Limited**

SCHEDULE 9e: REPORT ON NETWORK DEMAND

This schedule requires a summary of the key measures of network utilisation for the disclosure year (number of new connections including distributed generation, peak demand and electricity volumes conveyed).

sch ref

sch ref		
8	**9e(i): Consumer Connections and Decommissionings**	
9	*Number of ICPs connected during year by consumer type*	
10	*Consumer types defined by EDB**	**Number of connections (ICPs)**
11	015	190
12	030	10
13	045	16
14	LOW	22
15	Assessed	8
16	TOU400	5
17	**Connections total**	251
18	** include additional rows if needed*	
19		
20	*Number of ICPs decommissioned during year by consumer type*	
21	*Consumer types defined by EDB**	**Number of decommissionings**
22	015	55
23	LOW	11
24	045	4
25	Assessed	2
26		
27	**Decommissionings total**	72
28	** include additional rows if needed*	
29		

sch ref				
30		**Distributed generation**		
31		Number of connections made in year	188	**connections**
32		Capacity of distributed generation installed in year	1.84	**MVA**
33				

sch ref				
34		**9e(ii): System Demand**		
35				
36				
37		**Maximum coincident system demand**	**Demand at time of maximum coincident demand (MW)**	
38		GXP demand	139	
39	*plus*	Distributed generation output at HV and above	7	
40		**Maximum coincident system demand**	146	
41	*less*	Net transfers to (from) other EDBs at HV and above		
42		**Demand on system for supply to consumers' connection points**	146	
43		**Electricity volumes carried**	**Energy (GWh)**	
44		Electricity supplied from GXPs	839	
45	*less*	Electricity exports to GXPs	17	
46	*plus*	Electricity supplied from distributed generation	31	
47	*less*	Net electricity supplied to (from) other EDBs		
48		**Electricity entering system for supply to consumers' connection points**	853	
49	*less*	Total energy delivered to ICPs	818	
50		**Electricity losses (loss ratio)**	35	4.1%
51				
52		**Load factor**	0.67	

sch ref		
53	**9e(iii): Transformer Capacity**	
54		**(MVA)**
55	Distribution transformer capacity (EDB owned)	644
56	Distribution transformer capacity (Non-EDB owned)	16
57	**Total distribution transformer capacity**	660
58		
59		**(MVA)**
60	Zone substation transformer capacity (EDB owned)	396
61	Zone substation transformer capacity (Non-EDB owned)	
62	**Total zone substation transformer capacity**	396
63		

Company Name	**Alpine Energy Ltd**
For Year Ended	**31 March 2026**
Network / Sub-network Name	**Alpine Energy Limited**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

This schedule requires a summary of the key measures of network reliability (interruptions, SAIDI, SAIFI and fault rate) for the disclosure year. EDBs must provide explanatory comment on their network reliability for the disclosure year in Schedule 14 (Explanatory notes to templates). The SAIFI and SAIDI information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref			
8	**10(i): Interruptions**		
9	**Interruptions by class**	**Number of interruptions**	
10	Class A (planned interruptions by Transpower)	14	
11	Class B (planned interruptions on the network)	392	
12	Class C (unplanned interruptions on the network)	298	
13	Class D (unplanned interruptions by Transpower)	9	
14	Class E (unplanned interruptions of EDB owned generation)	–	
15	Class F (unplanned interruptions of generation owned by others)	–	
16	Class G (unplanned interruptions caused by another disclosing entity)	–	
17	Class H (planned interruptions caused by another disclosing entity)	–	
18	Class I (interruptions caused by parties not included above)	8	
19	**Total**	721	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	232	132
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)	0.13	31.6
26	Class B (planned interruptions on the network)	0.36	111.4
27	Class C (unplanned interruptions on the network)	1.46	184.6
28	Class D (unplanned interruptions by Transpower)	0.36	43.5
29	Class E (unplanned interruptions of EDB owned generation)	–	–
30	Class F (unplanned interruptions of generation owned by others)	–	–
31	Class G (unplanned interruptions caused by another disclosing entity)	–	–
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	0.02	1.4
34	**Total**	2.33	372.5
35			
36	**Transitional SAIFI and SAIDI (previous method)**	**SAIFI**	**SAIDI**
37	Class B (planned interruptions on the network)		
38	Class C (unplanned interruptions on the network)		
39			

40 *Where EDBs do not currently record their SAIFI and SAIDI values using the 'multi-count' approach, they shall continue to record their SAIFI and SAIDI values on the same basis that they employed as at 31 March 2023 as 'Transitional SAIFI' and 'Transitional SAIDI' values, in addition to their SAIFI and SAIDI values (Classes B & C) using the 'multi-count approach'.* ***This is a transitional reporting requirement that shall be in place for the 2024, 2025, and 2026 disclosure years.***

Company Name	**Alpine Energy Ltd**
For Year Ended	**31 March 2026**
Network / Sub-network Name	**Alpine Energy Limited**

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

This schedule requires a summary of the key measures of network reliability (interruptions, SAIDI, SAIFI and fault rate) for the disclosure year. EDBs must provide explanatory comment on their network reliability for the disclosure year in Schedule 14 (Explanatory notes to templates). The SAIFI and SAIDI information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

10(ii): Class C Interruptions and Duration by Cause

Cause	SAIFI	SAIDI
Lightning	0.07	5.6
Vegetation	0.23	36.2
Adverse weather	0.05	9.9
Adverse environment	–	–
Third party interference	0.23	18.4
Wildlife	0.24	20.9
Human error	0.11	4.2
Defective equipment	0.36	66.9
Other cause	–	–
Unknown	0.17	22.5

Breakdown of third party interference	SAIFI	SAIDI
Dig-in	0.02	1.0
Overhead contact	0.03	2.4
Vandalism	–	0.1
Vehicle damage	0.13	9.4
Other	0.03	5.1

Breakdown of vegetation interruptions (vegetation cause)	SAIFI	SAIDI	
In-zone	0.08	10.1	*Not required before DY2026*
Out-of-zone	0.14	25.4	*Not required before DY2026*

10(iii): Class B Interruptions and Duration by Main Equipment Involved

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	–	–
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.23	60.2
Distribution cables (excluding LV)	0.11	43.0
Distribution other (excluding LV)	–	0.9

10(iv): Class C Interruptions and Duration by Main Equipment Involved

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.04	15.6
Subtransmission cables	0.18	16.9
Subtransmission other	–	–
Distribution lines (excluding LV)	0.95	122.0
Distribution cables (excluding LV)	0.21	28.1
Distribution other (excluding LV)	0.08	1.7

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	8	157	5.10
Subtransmission cables	4	69	5.80
Subtransmission other	–		
Distribution lines (excluding LV)	238	2,984	7.98
Distribution cables (excluding LV)	36	459	7.84
Distribution other (excluding LV)	5		
Total	291		

Company Name	Alpine Energy Ltd
For Year Ended	31 March 2026
Network / Sub-network Name	Alpine Energy Limited

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

This schedule requires a summary of the key measures of network reliability (interruptions, SAIDI, SAIFI and fault rate) for the disclosure year. EDBs must provide explanatory comment on their network reliability for the disclosure year in Schedule 14 (Explanatory notes to templates). The SAIFI and SAIDI information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

8 **10(vi): Worst-performing feeders (unplanned)**

9

10 **SAIDI**

sch ref	Rank	Feeder name	Unplanned SAIDI values	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
11								
12	1	Geraldine G191 - Geraldine Township	23.90589214	6	Wildlife	26.33934191	1524	
13	2	Fairlie F380 - Fairlie Rural	22.28192176	24	DefectiveEquipment	212.4678384	771	
14	3	Albury ABY2742 - Cave	20.38877249	20	DefectiveEquipment	207.4416586	404	
15	4	Fairlie F383 - Fairlie Township	14.42846483	5	ThirdPartyInterference	3.154716086	341	
16	5	Timaru 2832 - Grants Road	13.8130471	1	DefectiveEquipment	8.327548122	1154	
17	6	Temuka 08 - Temuka East	10.32571822	2	VegetationOutZone	19.42327425	1476	
18	7	Studholme 01 - Otaio	7.420658382	7	DefectiveEquipment	115.5966453	353	
19	8	Geraldine G156 - Woodbury	6.841316764	13	VegetationOutZone	153.1191354	721	
20	9	Timaru 2952 - Highfield	5.998737193	3	CauseUnknown	22.86253326	1130	
21	10	Studholme 09 - Morven	4.496886032	19	ThirdPartyInterference	111.1695623	362	
22	11	Pareora CB4 - St Andrews	4.32379531	13	Wildlife	130.5403927	429	

27 [1] *Extend table as necessary to disclose all worst-performing feeders*

28

29 **SAIFI**

sch ref	Rank	Feeder name	Unplanned SAIFI values	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
30								
31	1	Geraldine G191 - Geraldine Township	0.314008553	6	Wildlife	26.33934191	1524	
32	2	Fairlie F380 - Fairlie Rural	0.099159085	24	DefectiveEquipment	212.4678384	771	
33	3	Fairlie F383 - Fairlie Township	0.090319433	5	ThirdPartyInterference	3.154716086	341	
34	4	Studholme 07 - Waihaorunga	0.070200614	7	DefectiveEquipment	22.05295476	808	
35	5	Temuka 08 - Temuka East	0.064690182	2	VegetationOutZone	19.42327425	1476	
36	6	Albury ABY2742 - Cave	0.062968172	20	DefectiveEquipment	207.4416586	404	
37	7	Geraldine G156 - Woodbury	0.050942801	13	VegetationOutZone	153.1191354	721	
38	8	Timaru 2952 - Highfield	0.044858365	3	CauseUnknown	22.86253326	1130	
39	9	Pareora CB7 - Holmestation	0.043279855	13	DefectiveEquipment	118.831025	315	
40	10	Studholme 08 - Mount Studholme	0.043279855	11	DefectiveEquipment	90.9786674	349	
41	11	Studholme 09 - Morven	0.042734552	19	ThirdPartyInterference	111.1695623	362	

46 [1] *Extend table as necessary to disclose all worst-performing feeders*

47

48 **Customer Impact**

sch ref	Rank	Feeder name	Customer Impact Ratio	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
49								
50	1	Timaru 2972 - Smithfield	6616.333333	1	DefectiveEquipment	0.985243999	3	
51	2	Albury ABY2742 - Cave	1758.430693	20	DefectiveEquipment	207.4416586	404	
52	3	Fairlie F383 - Fairlie Township	1474.284457	5	ThirdPartyInterference	3.154716086	341	
53	4	Fairlie F380 - Fairlie Rural	1006.963684	24	DefectiveEquipment	212.4678384	771	
54	5	Tekapo M201 - Simons Pass	850.7272727	1	ThirdPartyInterference	6.39953426	11	
55	6	Old Man Range M338 - Simons Pass	850.5	1	Wildlife	45.69941812	42	
56	7	Studholme 01 - Otaio	732.4589235	7	DefectiveEquipment	115.5966453	353	
57	8	Fairlie F374 - Cricklewood	706.6153846	6	DefectiveEquipment	31.87175477	52	
58	9	Temuka 07 - Rangitata	702.41875	9	DefectiveEquipment	48.12184235	160	
59	10	Tekapo M346 - Unwin Hut 33kV	612.1190476	7	Lightning	77.8729771	42	
60	11	Geraldine G191 - Geraldine Township	546.5570866	6	Wildlife	26.33934191	1524	

65 [1] *Extend table as necessary to disclose all worst-performing feeders*

Company Name: Alpine Energy Limited

For Year Ended: 31 March 2026

Schedule 14 Mandatory Explanatory Notes

1. This schedule requires EDBs to provide explanatory notes to information provided in accordance with clauses 2.3.1, 2.4.21, 2.4.22, and subclauses 2.5.1(1)(f), and 2.5.2(1)(e).

2. This schedule is mandatory – EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.1. Information provided in boxes 1 to 11 of this schedule is part of the audited disclosure information, and so is subject to the assurance requirements specified in section 2.8.

3. Schedule 15 (Voluntary Explanatory Notes to Schedules) provides for EDBs to give additional explanation of disclosed information should they elect to do so.

Return on Investment (Schedule 2)

4. In the box below, comment on the return on investment as disclosed in Schedule 2. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

Box 1: Explanatory comment on return on investment

The 2026 ROI-comparable to a post-tax WACC (reflecting all revenue earned) is 6.40% an increase from 2.92% in the prior year. This is 0.50% higher than the mid-point estimate of post-tax WACC for 2026. The resultant year-end ROI comparable to a post-tax WACC is 5.90%

The increase in revenue in 2026 ($16.8 million increase), provided for by the Commission's Default Price-Quality Path Determination 2025 is the most significant driver of the increased ROI.

There were no reclassified items in 2026.

Regulatory Profit (Schedule 3)

5. In the box below, comment on regulatory profit for the disclosure year as disclosed in Schedule 3. This comment must include-

    5.1 a description of material items included in other regulated income (other than gains / (losses) on asset disposals), as disclosed in 3(i) of Schedule 3; and

    5.2 information on reclassified items in accordance with subclause 2.7.1(2).

Box 2: Explanatory comment on regulatory profit
Regulatory profit/(loss) including financial incentives for the year to 31 March 2026 is $22.5 million, an increase of $11.4 million from 2025's profit of $11.1 million. *The most significant driver of the movement was an increase in lines charge revenue of $16.8 million).* *Our other regulated income in 2026 is $57,261 and comprises sales of scrap metal and a government grant from the Electricity Efficiency and Conservation Authority (EECA) for an energy efficiency project.* *There were no reclassified items in FY26.*

Merger and acquisition expenses (3(iv) of Schedule 3)

6. If the EDB incurred merger and acquisition expenditure during the disclosure year, provide the following information in the box below-

    6.1 information on reclassified items in accordance with subclause 2.7.1(2)

    6.2 any other commentary on the benefits of the merger and acquisition expenditure to the EDB.

Box 3: Explanatory comment on merger and acquisition expenditure
We did not merge with nor acquire another regulated business, and no items were reclassified.

Value of the Regulatory Asset Base (Schedule 4)

7. In the box below, comment on the value of the regulatory asset base (rolled forward) in Schedule 4. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

Box 4: Explanatory comment on the value of the regulatory asset based (rolled forward)

Our RAB value increased from $338 million to $361 million driven by:

- *$25.4 of assets were commissioned, a decrease of $3.9 from prior year (2025: $29.3 million); and*
- *$10.4 million in revaluation adjustments (2025: 7.9 million).*

The decrease in assets commissioned reflects a higher volume of consumer connections work (which is not added to the RAB) relative to network assets commissioned.

Depreciation is 4.1% of the opening RAB, in line with the prior years.

The revaluation rate increased to 3.08% in the current disclosure year, which is higher than prior year of 2.53%.

The works under construction (WUC) increased in the current year, from $10.9 million to $11.636 million. The cause of this increase was the implementation of a new GIS platform during 2026 that has delayed the capitalisation of some works.

There were no reclassified items in FY26.

Regulatory tax allowance: disclosure of permanent differences (5a(i) of Schedule 5a)

8. In the box below, provide descriptions and workings of the material items recorded in the following asterisked categories of 5a(i) of Schedule 5a-

   8.1 Income not included in regulatory profit / (loss) before tax but taxable;

   8.2 Expenditure or loss in regulatory profit / (loss) before tax but not deductible;

   8.3 Income included in regulatory profit / (loss) before tax but not taxable;

   8.4 Expenditure or loss deductible but not in regulatory profit / (loss) before tax.

Box 5: Regulatory tax allowance: permanent differences

Material items are deemed greater than $500,000.

Material expenditure of $596,353 on non-deductible consultancy expenditure is included in the regulatory profit / (loss) before tax.

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Regulatory tax allowance: disclosure of temporary differences (5a(vi) of Schedule 5a)

9. In the box below, provide descriptions and workings of material items recorded in the asterisked category 'Tax effect of other temporary differences' in 5a(vi) of Schedule 5a.

Box 6: Tax effect of other temporary differences (current disclosure year)

The opening balance of the temporary differences was $1,981,612. The closing balance is $2,092,778. The net movement is $111,166, driven by an increase in annual leave provision. The tax effect of this movement is $31,127.

Cost allocation (Schedule 5d)

10. In the box below, comment on cost allocation as disclosed in Schedule 5d. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

Box 7: Cost allocation

In the current disclosure year (similar to prior years) business support costs are the only costs that require allocation and the only costs that are not 100% directly attributable to the electricity distribution services.

The total business support costs incurred related to electricity distribution services were $16.3 million which is $ 2.5 million higher than the prior year. Directly attributable business support costs were $1.0 million which is $2.1 million lower than 2025. This variance is driven by costs in the prior year associated with resolving the historic price path error.

The total not directly attributable business support costs are $16.1 million which is $4.5 million - higher than the prior year. This increase is in line with our strategic investment in business change projects.

As in prior years, we used revenue as the proxy allocator for business support costs. Revenue from regulated versus non-regulated activities is deemed to be an accurate representation of the cost allocation as it closely reflects the activities' output (and therefore the costs associated with it).

No items have been reclassified as directly or non-directly attributable costs.

Asset allocation (Schedule 5e)

11. In the box below, comment on asset allocation as disclosed in Schedule 5e. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

Box 8: Commentary on asset allocation

In the current disclosure year (similar to prior years) non-network assets are the only assets that required allocation and also the only asset category which is not 100% directly attributable to the electricity distribution services.

Directly attributable non-network assets amount to $4.0 million and relate to plant and equipment including field services tools and equipment which are solely used for network purposes. Total not directly attributable non-network assets, amounting to $20.7 million, include vehicles, land, buildings and computers and software which are used by all departments. These therefore require allocation. The total non-network assets attributable to regulated service are $24.7 million.

We allocated the value of all non-directly attributable non-network assets (land and building, computers and software, motor vehicles) using expenditure incurred as allocated to the various cost centres as the proxy.

No items have been reclassified as directly or non-directly attributable assets.

Capital Expenditure for the Disclosure Year (Schedule 6a)

12. In the box below, comment on expenditure on assets for the disclosure year, as disclosed in Schedule 6a. This comment must include-

    12.1 a description of the materiality threshold applied to identify material projects and programmes described in Schedule 6a;

    12.2 information on reclassified items in accordance with subclause 2.7.1(2).

Box 9: Explanation of capital expenditure for the disclosure year

Schedule 6a discloses our capex as follows:

- *$29.9 million on network assets (2025: $30.1 million)*
- *$3.4 million on non-network assets (2025: $1.8 million)*
- *$7.2 million of capital contributions (2025: $2.9 million)*
- *$26.1 million total capital expenditure (2025: $29.1 million)*

The majority of capex ($14.4 million) was asset replacement and renewals (2025: $17.9 million). Material projects delivered were the overhead line renewal and replacement projects at Milford to Clandeboye ($1.2 million), Te Moana ($820,127), and Factory Road Temuka ($680,552),

Consumer connections expenditure increased significantly to $7.5M (2025: $3.3 million). An increase in capital contributions resulted from this increase in consumer activity, $7.2M compared to $2.8M in 2025. Material projects included the delivery of the first large scale solar farm on our network, an EV charger connection and industrial customer connections.

System growth expenditure was lower than in the prior year, 2.6 million, compared to $5.9 million in 2025. This variance reflects sometimes lumpy timing of growth projects across our 10-year AMP. $732,000 was invested in cable upgrades at Washdyke to support industrial growth.

The materiality of capex projects included in this explanatory box and detailed in Schedule 6a is based on the impact of the project on network reliability, resilience, and capacity, and consumer outcomes, rather than a specific monetary threshold. Where applicable, we refer to a programme of work that delivers a material outcome for the network or customers, as opposed to a discrete project.

No items have been reclassified during this disclosure year.

Operational Expenditure for the Disclosure Year (Schedule 6b)

13. In the box below, comment on operational expenditure for the disclosure year, as disclosed in Schedule 6b. This comment must include-

14. Commentary on assets replaced or renewed with asset replacement and renewal operational expenditure, as reported in 6b(i) of Schedule 6b;

    14.1 Information on reclassified items in accordance with subclause 2.7.1(2);

    14.2 Commentary on any material atypical expenditure included in operational expenditure disclosed in Schedule 6b, including the value of the expenditure the purpose of the expenditure, and the operational expenditure categories the expenditure relates to.

Box 10: Explanation of operational expenditure for the disclosure year

Schedule 6b discloses our opex as follows:

- *$6.5 million of network opex (2025: $7.7 million)*
- *$27.6 million of non-network opex (2025: $25.3 million)*

$55,000 was spent on asset renewal and replacement opex, with no material assets being replaced.

The increase in non-network opex reflects our investment strategic business change projects, including the first phase of implementing new Enterprise Resource Planning and Enterprise Asset Management systems.

Variance between forecast and actual expenditure (Schedule 7)

15. In the box below, comment on the variance in actual to forecast expenditure for the disclosure year, as reported in Schedule 7. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

Box 11: Explanatory comment on variance in actual to forecast expenditure

We have deemed any variance greater than +/-10% and greater than $1 million as a material variance. The forecast amounts were taken from the Asset Management Plan (AMP) published at the start of the disclosure year. There were no re-classified items.

Capital expenditure

Total actual capital expenditure of 2026 is 8% lower than the forecast. This is driven by lower than forecast system growth, renewal and replacement, and non-network expenditure which offset higher than forecast consumer connection expenditure.

Consumer connection

The actual capital expenditure on consumer connection was 62%, or $2.9 million, higher than forecast. Our 2025 AMP forecasts were conservative due to the recessionary climate at the time. The increase was largely driven by more industrial and commercial activity than forecast.

System growth

The actual capital expenditure on system growth was 28% ($1.0 million) lower than forecast due to two large projects being delayed by design and consenting matters.

Asset replacement and renewal

The very wet summary and industrial action taken by unionised field service workers impacted the delivery of the replacement and renewal programme, with expenditure $2.3 million lower (14%) than forecast.

Reliability safety and environment

Variances within reliability, safety and environment subcategories are a result of projects being forecast as 'quality of supply' being deferred or completed as part of other projects. The increase in 'other reliability, safety and environment' expenditure' was driven by increased project cost, and new projects being delivered (e.g. bird strike mitigation project not included in AMP forecasts).

Non-network assets

The deferral of a yard development project, and the delayed arrival of a field service heavy vehicle drove expenditure $2.5 million less than forecast.

Operational expenditure

Total actual operational expenditure of 2026 is 2.6 million (7%) lower than forecast.

Network Opex

Network opex was lower than forecast, primarily due to routine and corrective maintenance and inspection expenditure being $1.332m below forecast. This reflected a change from rate card pricing to actual cost-based pricing.

Non-Network Opex

Non-network opex was $1.5m or 5% lower than forecast. The main movements reflect changes in cost mapping between system operations and network support, which was $5.0m higher than forecast, and business support, which was $6.5m lower than forecast. Overall, total non-network opex remained broadly consistent with forecast.

No material items have been reclassified during this disclosure year affecting the variance report.

Information relating to revenues and quantities for the disclosure year

16. In the box below provide-

16.1 a comparison of the target revenue disclosed before the start of the disclosure year, in accordance with clause 2.4.1 and subclause 2.4.3(3) to total billed line charge revenue for the disclosure year, as disclosed in Schedule 8; and

16.2 explanatory comment on reasons for any material differences between target revenue and total billed line charge revenue.

Box 12: Explanatory comment relating to revenue for the disclosure year

Our actual revenue of $81.9 million was $321,000 higher (0.4%) than the target revenue disclosed in our 2026 Pricing Methodology.

There is no material difference between target and actual revenue.

Network Reliability for the Disclosure Year (Schedule 10)

17. In the box below, comment on network reliability for the disclosure year, as disclosed in Schedule 10.

Box 13: Commentary on network reliability for the disclosure year

Overall outage duration improved on the prior year, while interruptions were more frequent. A decrease in Class B planned interruptions, and Class D unplanned Transpower interruptions drive the improved SAIDI performance for 2026.

There were material increases in the frequency and duration of Class C unplanned interruptions. Vegetation, third party interference and defective equipment were the most significant causers of these interruptions. Class C SAIDI increases compared to prior year were driven by longer restorations times for defective equipment, mainly distribution lines and cables, and vegetation related interruptions.

New disclosures for in-zone and out-of-zone vegetation related interruptions reveals that out-of-zone vegetation caused nearly twice as many interruptions as in-zone vegetation, and the duration of outages was more than double.

Insurance cover

18. In the box below, provide details of any insurance cover for the assets used to provide electricity distribution services, including-

18.1 The EDB's approaches and practices in regard to the insurance of assets used to provide electricity distribution services, including the level of insurance;

18.2 In respect of any self-insurance, the level of reserves, details of how reserves are managed and invested, and details of any reinsurance.

Box 14: Explanation of insurance cover

We take our insurance cover for our vehicles and buildings (including substations) and have public liability insurance. We do not have insurance coverage for our network (for example poles and lines) as the premiums are prohibitive.

Amendments to previously disclosed information

19. In the box below, provide information about amendments to previously disclosed information disclosed in accordance with clause 2.12.1 in the last 7 years, including:

    19.1 a description of each error; and

    19.2 for each error, reference to the web address where the disclosure made in accordance with clause 2.12.1 is publicly disclosed.

Box 15: Disclosure of amendment to previously disclosed information

There were no amendments to previously disclosed information during this disclosure year.

Company Name: Alpine Energy Limited

For Year Ended: 31 March 2025

Schedule 15 Voluntary Explanatory Notes

1. This schedule enables EDBs to provide, should they wish to-

    1.1 additional explanatory comment to reports prepared in accordance with clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1, 2.5.2, and 2.6.6;

    1.2 information on any substantial changes to information disclosed in relation to a prior disclosure year, as a result of final wash-ups.

2. Information in this schedule is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

3. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information

Treatment of payments made under Alpine Energy's enforceable undertakings

Alpine Energy's enforceable undertakings to the Commerce Commission, dated 28 March 2025, required a number of payments to address the historic overcharge of consumers from 2015 to 2024. The intent of the undertakings was to return the overcharge to consumers without the need to reopen the existing price-quality paths. Alpine has agreed to these payments outside of the revenue cap and information disclosure mechanisms. There has been no impact of these payments on the 2026 Annual Compliance Statement/Information Disclosures. In addition, credits to consumers are excluded from both the Default Price-Quality Path (DPP) and Information Disclosures (ID) except if less than $16.9m is credited. Any such difference along with credits to former customers and any unspent amounts of the community fund impact the DPP and lines charge revenue (IDs) in the 2027 regulatory period in line with the enforceable undertakings.

Treatment of connection expenditure, capital contributions and assets commissioned relating to distributed generation customer

In 2026 Alpine Energy completed connection works for a distributed generation customer. The capex on assets to establish this new connection are reflected in schedule 6a(i) and (iii) – consumer connection capex. The capital contributions received from the customer for the purposes of connection asset construction are reflected in schedule 6a(i) and (iii) – value of capital contributions. This is in line with the Input Methodology and Information Disclosure Determinations. The assets constructed are part of Alpine Energy's electricity distribution network.

As part of our distribution network these assets, and the services they provide, are not excluded from regulated electricity lines services under Section 54C(2)(c) of the Commerce Act, which excludes lines "conveying electricity (other than via the national grid) only from a generator to a local distribution network, or from a local distribution network to a generator.

In accordance with the Input Methodologies clause 2.2.11(h) – value of assets commissioned, the value of the connection assets included in schedule 4 – RAB value (rolled forward) is $0, i.e. the cost of the asset, reduced by the amount of the capital contributions.

The assets constructed are included in our asset data reflected in schedules 9a, b and c, and in schedule 10 interruptions data.

Schedule 5b - Related Parties Transactions & Related Parties Disclosure Document

Field Services is Alpine Energy's internal function responsible for constructing and maintaining the electricity distribution network. These services were previously provided by the subsidiary NETCon Limited, along with other third parties. Following the amalgamation of NETcon into Alpine Energy in the 2024 financial year, we have evaluated whether Field Services should be treated as a related party for ID purposes.

As with the prior year, we have determined that Field Services does not fall within the related parties' Information Disclosure (ID) requirements and therefore we are not required to include transactions relating to Field Services in our related party disclosures. The rationale for this is that:

- *Alpine Energy's supplies to external customers (unregulated) do not exceed the unregulated supplies to the regulated service.*
- *These unregulated services do not have a management, sales, and support structure that is theoretically capable of being separated from the regulated supplier.*

As a result, the Field Services function is considered part of the regulated supplier (Alpine Energy).

Field Services operates on a cost-recovery basis, except when providing services to external customers (unregulated services). Costs and assets associated with the delivery of these unregulated services are addressed through the ID cost allocation regime, identifying the non-

directly attributable portion of operating costs and assets. These are disclosed in schedules 5d, 5e, 5f and 5g, and the supporting disclosures in schedule 14.

Schedule 9a and b - Asset data

Our 2026 asset register shows a net loss of 3393 assets and 115km of line/cable. This data should not be interpreted as a real *decrease in physical asset quantity and line/cable length on our network. A lag in data processing time for assets removed, and assets installed as part of renewal and replacement projects is the cause of this variance. For example, pole removed from the network, as part of our pole replacement programme, will be reflected more quickly our asset register than the new pole installed.*

In 2026 Alpine Energy implemented a new GIS system, resulting in a backlog of asset data processing. This backlog as impacted the asset register data due to the 'point-in-time' nature of this disclosure.

Data cleansing, as part of the GIS replacement project, has also rectified ownership issues in historic data, where customer or third-party assets were incorrectly included in asset register data. Removing these assets has partly driven the negative change in assets.

Alpine Energy acknowledges our current asset design, commissioning and recording processes are not scaled effectively to support our organisation's growth and operational requirements. To address this, Alpine is implementing a new Enterprise Resource Management system. This project will replace the existing asset and resource management systems and redesign business processes to improve data quality, timeliness of asset recoding, scalability, and reporting capability. The project is expected to be completed by 2028.

Schedule 10 – Reliability

There are inherent limitations in the ability of Alpine Energy to collect and record the network reliability information required to be disclosed in Schedule 10(i) to 10(iv), 10.2 and 10a (Commission only). Consequently, there is no independent evidence available to support the accuracy of recorded faults and control over the accuracy of installation control point ('ICP') data included in the SAIDI and SAIFI calculations is limited throughout the year. This limitation will be removed once we move to an ADMS system, which is planned to be implemented in the next three to five years.

We treat successive interruptions in the following way:

a. *Relates directly to that initial interruption. These would usually be reported as a separate outage, if however, the original outage was classed as unknown it is updated as if the following fault can be confirmed to have caused the original.*
b. *Occurs as part of the process of restoring the supply of electricity lines services following that initial interruption. In this situation, the outage would be recorded as part of the original fault, and the cause would be the same for both, but where ICPs go off more than once they would be reported as such to keep the SAIFI correct.*

Appendix A
Related Party Transactions
for the year ended 31 March 2026

This disclosure has been prepared to meet the 2026 Related Party Transaction disclosure requirements, in accordance with the Electricity Distribution Information Disclosure (amendments related to IM Review 2023) Amendment Determination 2024 (ID Determination).

The information is provided in reference to, and in support of, Schedule 5b – Related Party Transactions as disclosed in the Information Disclosure Schedules for the disclosure year ended 31 March 2026.

In accordance with clauses 2.3.8 of the ID Determination, Table 1 below summarises the relationship between AEL and the related parties with which we had related party transactions (as defined in the Electricity Distribution Services Input Methodologies Determination 2012, consolidated to include amendments as at 23 April 2024 (IM Determination) during the disclosure year. Table 1 also summarises the principal activities of the related parties and the total annual expenditure incurred.

AEL does have other subsidiaries and joint venture relationships which are not included in Table 1 below. AEL did not procure or sell any assets or goods and services from or to these related parties for the supply of electricity distribution services. For a full list of all related parties, refer to AEL's Annual Report for the year ended 31 March 2026, as publicly disclosed on AEL's website[1].

Related Party	Relationship	Annual expenditure $'000	Principal Activities of the Related Party
Timaru District Council (TDC)	Shareholder - 47.5% ownership (through a 100% ownership in Timaru District Holdings Limited).	$61	TDC is the territorial authority for the Timaru District area in accordance with the Local Government Act 2002. TDC provides infrastructure and regulatory services, community facilities and promotes the social, cultural, economic, and environmental wellbeing of the Timaru District community.
Timaru District Holdings Limited (TDHL)	Shareholder - 47.5% ownership	$2	TDHL is a council-controlled organisation that olds and manages commercial assets and investments on behalf of Timaru District Council.

[1] https://www.alpineenergy.co.nz/corporate/reports-and-publications/annual-reports

Related Party	Relationship	Annual expenditure $'000	Principal Activities of the Related Party
Waimate District Council (WDC)	Shareholder - 7.54% ownership	$41	WDC is the territorial authority for the Waimate District area in accordance with the Local Government Act 2002. WDC provides infrastructure and regulatory services, community facilities and promotes the social, cultural, economic, and environmental wellbeing of the Waimate District community.
Mackenzie District Council (MDC)	Shareholder - 4.96% ownership	$40	MDC is the territorial authority for the Mackenzie District area in accordance with the Local Government Act 2002. MDC provides infrastructure and regulatory services, community facilities and promotes the social, cultural, economic, and environmental wellbeing of the Mackenzie District community.
Alpine Directors	Alpine Directors	$502	Director services to AEL.

In this regulatory year, AEL invoiced Timaru District Holdings ($13,294) for installing a new connection on an arms-length basis. Other related party transactions comprised engraving services of $1,779 provided by Laser Grafix, an entity associated with a member of key management personnel.

The Audit Office
Te Mana Arotake

Independent Assurance Report

To the directors of Alpine Energy Limited and to the Commerce Commission on the disclosure information for the disclosure year ended 31 March 2026 as required by the Electricity Distribution Information Disclosure (Amendments related to IM Review 2023) Amendment Determination 2024 [2024] NZCC 31 (as amended)

Alpine Energy Limited (the company) is required to disclose certain information under the Electricity Distribution Information Disclosure (Amendments related to IM Review 2023) Amendment Determination 2024 [2024] NZCC 31 (as amended) (the Determination) and to procure an assurance report by an independent auditor in terms of section 2.8.1 of the Determination.

The Auditor-General is the auditor of the company.

The Auditor-General has appointed me, Elizabeth Adriana (Adri) Smit, using the staff and resources of PricewaterhouseCoopers, to undertake a reasonable assurance engagement, on his behalf, on whether the information prepared by the company for the disclosure year ended 31 March 2026 (the Disclosure Information) complies, in all material respects, with the Determination.

The Disclosure Information that falls within the scope of the assurance engagement are:

- Schedules 1, 2, 3, 3a, 4, 5a to 5h, 6a and 6b (except for information required to be disclosed in Schedule 6(b)(i) under the "Vegetation-related" and "Other" sub-categories of the "Service interruptions and emergencies" category, and the "assessment and notification costs", "Felling or trimming vegetation – in-zone", "Felling or trimming vegetation – out-of-zone", and "Other" sub-categories of the "Vegetation management" category), 7, 10 and 10a (limited to the SAIDI and SAIFI information) and 14 (limited to the explanatory notes in boxes 1 to 11) of the Determination.

- The basis for the valuation of related party transactions (the Related Party Transaction Information) in accordance with clause 2.3.6 of the Determination and clauses 2.2.11(1)(g), 2.2.11(5) and 2.2.11(6) of the Electricity Distribution Services Input Methodologies Determination 2012 (as amended) (the IM Determination); and the information disclosed under clauses 2.3.8, 2.3.10 to 2.3.12.

Qualified Opinion

In our opinion, except for the possible effect of the matter described in the Basis for Qualified Opinion section of our report, in all material respects:

- as far as appears from an examination, proper records to enable the complete and accurate compilation of the Disclosure Information have been kept by the company;
- as far as appears from an examination, the information used in the preparation of the Disclosure Information has been properly extracted from the company's accounting and other records, sourced from the company's financial and non-financial systems;
- the Disclosure Information complies, with the Determination; and
- the basis for valuation of related party transactions complies with the Determination and the IM Determination.

Basis for Qualified opinion

As described in box 1 of Schedule 15, there are inherent limitations in the ability of the Company to collect and record the network reliability information specifically the interconnection points ('ICP's') affected by an interruption and the duration of the interruption used in calculating the amounts required to be disclosed in the Schedules 10 and 10a. Consequently, there is no independent evidence available to support the completeness and accuracy of recorded faults, and control over the completeness and accuracy of interconnection point ('ICP') data included in the SAIDI and SAIFI calculations was limited throughout the year.

There are no practical audit procedures that we could adopt to independently confirm that all the faults and ICP data were properly recorded for the purposes of inclusion in the amounts relating to quality measures set out in Schedules 10 and 10a.

Because of the potential effect of these limitations, we are unable to obtain sufficient appropriate audit evidence to confirm the completeness and accuracy of the data that forms the basis of the compilation of Schedules 10 and 10a. We conducted our engagement in accordance with the International Standard on Assurance Engagements (New Zealand) 3000 (Revised) Assurance Engagements Other Than Audits or Reviews of Historical Financial Information ("ISAE (NZ) 3000 (Revised)") and the Standard on Assurance Engagements (SAE) 3100 (Revised) Compliance Engagements ("SAE 3100 (Revised)"), issued by the New Zealand Auditing and Assurance Standards Board.

We have obtained sufficient recorded evidence and explanations that we required to provide a basis for our qualified opinion.

Key Assurance Matters

Key assurance matters are those matters that, in our professional judgement, required significant attention when carrying out the assurance engagement during the current disclosure year. These matters were addressed in the context of our compliance engagement, and in forming our opinion. We do not provide a separate opinion on these matters.

<table>
<tr><th>Key Assurance Matter</th><th>How our procedures addressed the key assurance matter</th></tr>
<tr><td>

Regulatory Asset Base

The Regulatory Asset Base (RAB), as set out in Schedule 4, reflects the value of the Company's electricity distribution assets. These are valued using an indexed historic cost methodology prescribed by the Determination. It is a measure which is used widely and is key to measuring the Company's return on investment and therefore important when monitoring financial performance or setting electricity distribution prices.

The RAB inputs, as set out in the IM Determination, are similar to those used in the measurement of fixed assets in the financial statements, however, there are a number of different requirements and complexities which require careful consideration.

Due to the importance of the RAB within the regulatory regime, the incentives to overstate the RAB value, and complexities within the regulations, we have considered it to be a key area of focus.

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We have obtained an understanding of the compliance requirements relevant to the RAB as set out in the Determination and the IM Determination.

Our procedures over the regulatory asset base included the following:

Assets commissioned

- We considered the nature of the assets commissioned during the period, as per the regulatory fixed asset register, to identify any specific cost or asset type exclusions, as set out in the Determination, which are required to be removed from the RAB;
- We reconciled the assets commissioned, as per the regulatory fixed asset register, to the asset additions in the underlying accounting records and investigated any material reconciling items; and
- We tested a sample of assets commissioned during the disclosure period for appropriate asset category classification.

Depreciation

- For assets with no standard asset lives we assessed the reasonableness of the lives used by reference to the accounting depreciation rates used in preparing the underlying financial records;
- We have performed a reasonableness test to ensure the regulatory depreciation expense is calculated in line with IM Determination clause 2.2.5; and
- We compared the standard asset lives by asset category to those set out in the IM Determination.

Revaluation

- We recalculated the revaluation rate set out in the IM Determination using the relevant Consumer Price Index indices taken from the Statistics New Zealand website; and
- We tested the mathematical accuracy of the revaluation calculation performed by management.

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<table>
<tr><th>Key Assurance Matter</th><th>How our procedures addressed the key assurance matter</th></tr>
<tr><td>
Cost and Asset Allocation
The Determination relates to information concerning the supply of electricity distribution services. In addition to the regulated supply of electricity, the Company also supplies customers with other unregulated services such as metering services.
As set out in schedules 5d, 5e, 5f and 5g, costs and asset values that relate to electricity distribution services regulated under the Determination should comprise:

All of the costs directly attributable to the regulated goods or services; and
An allocated portion of the costs that are not directly attributable.

The IM Determination set out rules and processes for allocating costs and assets which are not directly attributable to either regulated or unregulated services. A number of screening tests apply which must be considered when deciding on the appropriate allocation method.
The Company has applied the Accounting-Based Allocation Approach Methodology (ABAA) utilising proxy cost and asset allocators to allocate the asset values and operating costs that are not directly attributable where causal relationships could not be identified.
Given the judgement involved in the application of the cost and asset allocation methodologies we consider it a key assurance matter.
</td><td>
We obtained an understanding of the Company’s cost and asset allocation processes and the methodologies applied.
Our procedures over cost and asset allocation included:

Reconciling the regulated and unregulated financial information to the audited financial statements;

Classification as directly/not directly attributable

Considering the appropriateness of the costs allocated as directly attributable, based on the nature and our understanding of the business to determine the reasonableness of the directly attributable classification;
Testing a sample of transactions to ensure their classification as either directly attributable or not directly attributable costs are appropriate and in line with the Determination;
Inspecting the fixed asset register to identify any asset classes which based on their nature and our understanding of the business could be considered assets directly attributable to a specific business unit;
Testing a sample of assets commissioned to ensure their classification as either directly attributable or not directly attributable are appropriate and in line with the Determination;

Appropriateness of the allocators used for not directly attributable costs and assets

Considering the appropriateness of the cost and asset causal and proxy allocators used in applying the ABAA to not directly attributable costs including inspecting supporting documentation and recalculating proxy allocators;
Understanding why causal relationships could not be identified in allocating some costs or assets and ensuring appropriate disclosure has been included outlining these in Schedule 14;
Recalculating the split between not directly attributable costs and asset values allocated to electricity distribution services and non-electricity distribution services.

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Directors’ responsibilities

The directors of the company are responsible in accordance with the Determination for:

- the preparation of the Disclosure Information; and
- the Related Party Transaction Information.

The directors of the company are also responsible for the identification of risks that may threaten compliance with the schedules and clauses identified above and controls which will mitigate those risks and monitor ongoing compliance.

Auditor's responsibilities

Our responsibilities in terms of clauses 2.8.1(1)(b)(vi) and (vii), 2.8.1(1)(c) and 2.8.1(1)(d) are to express an opinion on whether:

- as far as appears from an examination, the information used in the preparation of the audited Disclosure Information has been properly extracted from the company's accounting and other records, sourced from its financial and non-financial systems;
- as far as appears from an examination, proper records to enable the complete and accurate compilation of the audited Disclosure Information required by the Determination have been kept by the company and, if not, the records not so kept;
- the company complied, in all material respects, with the Determination in preparing the audited Disclosure Information; and
- the company's basis for valuation of related party transactions in the disclosure year has complied, in all material respects, with clause 2.3.6 of the Determination and clauses 2.2.11(1)(g), 2.2.11(5) and 2.2.11(6) of the IM Determination.

To meet these responsibilities, we planned and performed procedures in accordance with ISAE (NZ) 3000 (Revised) and SAE 3100 (Revised), to obtain reasonable assurance about whether the company has complied, in all material respects, with the Disclosure Information (which includes the Related Party Transaction Information) required to be audited by the Determination.

An assurance engagement to report on the company's compliance with the Determination involves performing procedures to obtain evidence about the compliance activity and controls implemented to meet the requirements. The procedures selected depend on our judgement, including the identification and assessment of the risks of material non-compliance with the requirements.

Inherent limitations

Because of the inherent limitations of an assurance engagement, together with the internal control structure, it is possible that fraud, error or non-compliance with the Determination may occur and not be detected.

A reasonable assurance engagement throughout the disclosure year does not provide assurance on whether compliance with the Determination will continue in the future.

Restricted use

This report has been prepared for use by the directors of the company and the Commerce Commission in accordance with clause 2.8.1(1)(a) of the Determination and is provided solely for the purpose of establishing whether the compliance requirements have been met. We disclaim any assumption of responsibility for any reliance on this report to any person other than the directors of the company and the Commerce Commission, or for any other purpose than that for which it was prepared.

Independence and quality control

We complied with the Auditor-General's independence and other ethical requirements, which incorporate the requirements of Professional and Ethical Standard 1 International Code of Ethics for Assurance Practitioners (including International Independence Standards) (New Zealand) as applicable for audits of public interest entities (PES 1) issued by the New Zealand Auditing and Assurance Standards Board. PES 1 is founded on the fundamental principles of integrity, objectivity, professional competence and due care, confidentiality and professional behaviour.

We have also complied with the Auditor-General's quality management requirements, which incorporate the requirements of Professional and Ethical Standard 3 Quality Management for Firms that Perform Audits or Reviews of Financial Statements, or Other Assurance or Related Services Engagements (PES 3) issued by the New Zealand Auditing and Assurance Standards Board. PES 3 requires our firm to design, implement and operate a system of quality management including policies or procedures regarding compliance with ethical requirements, professional standards and applicable legal and regulatory requirements.

The Auditor-General, and his employees, and PricewaterhouseCoopers and its partners and employees may deal with the company on normal terms within the ordinary course of trading activities of the company. In addition to this engagement, we have carried out engagements on behalf of the Auditor-General in the areas of the assurance engagement on the Default Price-Quality Path and the annual audit of the company's financial statements and performance information, and engagements independently of our relationship with the Auditor-General as PricewaterhouseCoopers being an assurance engagement on the Price Setting Compliance Statement, which are compatible with the independence requirements. Other than the audit and these engagements, we have no relationship with, or interests in, the company.

Elizabeth Adriana (Adri) Smit
PricewaterhouseCoopers
On behalf of the Auditor-General
Christchurch, New Zealand
28 August 2026