EDB Information Disclosure Requirements

Schedules 1–10
excluding 5f–5h

Company Name	Alpine Energy Limited
Disclosure Date	31 August 2025
Disclosure Year (year ended)	31 March 2025

Schedules 1–10 excluding 5f–5h
Prepared 27 November 2024

Table of Contents

Disclosure Template Instructions

This document forms Schedules 1–10 to the Electricity Distribution Information Disclosure (Amendments related to the IMs 2024) Amendment Determination 2024 [2024] NZCC 2.

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.

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 accordingly.

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 Limited**
For Year Ended	**31 March 2025**

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**	39,816	973	214,367	7,529	52,521
10	Network	9,296	227	50,047	1,758	12,262
11	Non-network	30,520	746	164,320	5,772	40,259
12						
13	**Expenditure on assets**	38,572	943	207,669	7,294	50,880
14	Network	36,357	889	195,743	6,875	47,958
15	Non-network	2,215	54	11,925	419	2,922
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**	78,588	1,921
20	Standard consumer line charge revenue	95,366	1,763
21	Non-standard consumer line charge revenue	26,624	448,916
22			

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

sch ref			
24			
25	Demand density	35	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
26	Volume density	189	*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	24,442	*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	33,007	50.66%
33	Pass-through and recoverable costs excluding financial incentives and wash-ups	14,973	22.98%
34	Total depreciation	13,664	20.97%
35	Total revaluations	7,860	12.06%
36	Regulatory tax allowance	307	0.47%
37	Regulatory profit/(loss) including financial incentives and wash-ups	11,067	16.98%
38	**Total regulatory income**	65,157	
39			

40 **1(v): Reliability**

sch ref			
41			
42	Interruption rate	38.42	*Interruptions per 100 circuit km*

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2025**

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		CY-2	CY-1	Current Year CY
7	**2(i): Return on Investment**			
8		31 Aug 23	31 Aug 24	31 Aug 25
9	**ROI – comparable to a post tax WACC**	%	%	%
10	Reflecting all revenue earned	7.92%	5.96%	2.92%
11	Excluding revenue earned from financial incentives	7.83%	5.30%	2.12%
12	Excluding revenue earned from financial incentives and wash-ups	7.86%	5.33%	2.16%
13				
14	**Mid-point estimate of post tax WACC**	4.88%	6.05%	6.18%
15	25th percentile estimate	4.20%	5.37%	5.50%
16	75th percentile estimate	5.56%	6.73%	6.86%
17				
18				
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	8.43%	6.66%	3.64%
21	Excluding revenue earned from financial incentives	8.34%	6.00%	2.84%
22	Excluding revenue earned from financial incentives and wash-ups	8.38%	6.03%	2.88%
23				
24	**WACC rate used to set regulatory price path**	4.57%	4.57%	4.57%
25				
26	**Mid-point estimate of vanilla WACC**	5.39%	6.75%	6.90%
27	25th percentile estimate	4.71%	6.07%	6.22%
28	75th percentile estimate	6.07%	7.43%	7.58%
29				

30	**2(ii): Information Supporting the ROI**			($000)	
31					
32		Total opening RAB value	313,092		
33	*plus*	Opening deferred tax	(20,582)		
34	**Opening RIV**			292,510	
35					
36	**Line charge revenue**			65,148	
37					
38		Expenses cash outflow	47,980		
39	*add*	Assets commissioned	29,348		
40	*less*	Asset disposals	398		
41	*add*	Tax payments	(725)		
42	*less*	Other regulated income	9		
43	**Mid-year net cash outflows**			76,196	
44					
45	**Term credit spread differential allowance**			–	
46					
47		Total closing RAB value	338,231		
48	*less*	Adjustment resulting from asset allocation	1,993		
49	*less*	Lost and found assets adjustment	–		
50	*plus*	Closing deferred tax	(21,613)		
51	**Closing RIV**			314,625	
52					
53	**ROI – comparable to a vanilla WACC**				3.64%
54					
55		Leverage (%)			42%
56		Cost of debt assumption (%)			6.12%
57		Corporate tax rate (%)			28%
58					
59	**ROI – comparable to a post tax WACC**				2.92%
60					

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2025**

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

61 **2(iii): Information Supporting the Monthly ROI**

sch ref		Line charge revenue	Expenses cash outflow	Assets commissioned	Asset disposals	Other regulated income	Monthly net cash outflows
62							
63	**Opening RIV**						N/A
64							
65							
66							
67	April						–
68	May						–
69	June						–
70	July						–
71	August						–
72	September						–
73	October						–
74	November						–
75	December						–
76	January						–
77	February						–
78	March						–
79	**Total**	–	–	–	–	–	–
80							
81	**Tax payments**						N/A
82							
83	**Term credit spread differential allowance**						N/A
84							
85	**Closing RIV**						N/A
86							
87							
88	**Monthly ROI – comparable to a vanilla WACC**						N/A
89							
90	**Monthly ROI – comparable to a post tax WACC**						N/A
91							

92 **2(iv): Year-End ROI Rates for Comparison Purposes**

sch ref		
93		
94	**Year-end ROI – comparable to a vanilla WACC**	2.56%
95		
96	**Year-end ROI – comparable to a post tax WACC**	1.84%
97		
98	** 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.*	
99		

100 **2(v): Financial Incentives and Wash-Ups**

sch ref			
101			
102	IRIS incentive adjustment	3,403	
103	Purchased assets – avoided transmission charge	–	
104	Innovation and non-traditional solutions recovered amount	–	
105	Quality incentive adjustment	(71)	
106	Other CPP financial incentives	–	
107	**Financial incentives**		3,332
108			
109	**Impact of financial incentives on ROI**		0.80%
110			
111	Input methodology claw-back	–	
112	CPP application recoverable costs	–	
116	Catastrophic event allowance	–	Not Required after DY2
117	Capex wash-up adjustment	(142)	Not Required after DY2
118	Transmission asset wash-up adjustment	–	Not Required after DY2
119	2013–15 NPV wash-up allowance	–	Not Required after DY2
120	Reconsideration event allowance	–	Not Required after DY2
121	Other CPP wash-ups	–	
122	**Wash-up costs**		(142)
123			
124	**Impact of wash-up costs on ROI**		–0.03%

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2025**

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		65,148
10	*plus*	Gains / (losses) on asset disposals		3
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)		6
12				
13		**Total regulatory income**		65,157
14		**Expenses**		
15	*less*	Operational expenditure		33,007
16				
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups		14,973
18				
19		**Operating surplus / (deficit)**		17,178
20				
21	*less*	Total depreciation		13,664
22				
23	*plus*	Total revaluations		7,860
24				
25		**Regulatory profit / (loss) before tax**		11,374
26				
27	*less*	Term credit spread differential allowance		–
28				
29	*less*	Regulatory tax allowance		307
30				
31		**Regulatory profit/(loss) including financial incentives and wash-ups**		11,067
32				
33		**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34		**Pass through costs**		
38		Rates	161	
39		Commerce Act levies	204	
40		Industry levies	226	
41		CPP or DPP specified pass-through costs	–	
42		**Recoverable costs excluding financial incentives and wash-ups**		
45		Electricity lines service charge payable to Transpower	13,138	Not Required after DY2
46		Transpower new investment contract charges	1,244	Not Required after DY2
47		System operator services	–	Not Required after DY2
48		Distributed generation allowance	–	Not Required after DY2
49		Extended reserves allowance	–	
50		Other CPP recoverable costs excluding financial incentives and wash-ups	–	
51		**Pass-through and recoverable costs excluding financial incentives and wash-ups**		14,973
52				
53		**3(iv): Merger and Acquisition Expenditure**		
54				**($000)**
55		Merger and acquisition expenditure		–
56				
57		*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)*		
58		**3(v): Other Disclosures**		
59				**($000)**
60		Self-insurance allowance		–

Company Name	Alpine Energy Limited
For Year Ended	31 March 2025

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

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

sch ref			RAB CY-4 ($000)	RAB CY-3 ($000)	RAB CY-2 ($000)	RAB CY-1 ($000)	RAB CY ($000)
10		**Total opening RAB value**	227,918	236,905	267,127	293,278	313,092
11							
12	*less*	**Total depreciation**	9,319	9,610	11,083	11,923	13,664
13							
14	*plus*	**Total revaluations**	3,466	16,319	17,777	11,785	7,860
15							
16	*plus*	**Assets commissioned**	14,839	18,554	19,465	21,008	29,348
17							
18	*less*	**Asset disposals**	–	54	7	328	398
19							
20	*plus*	**Lost and found assets adjustment**	–	–	–	–	–
21							
22	*plus*	**Adjustment resulting from asset allocation**	–	5,012	–	(728)	1,993
23							
24		**Total closing RAB value**	236,905	267,127	293,278	313,092	338,231
25							

4(ii): Unallocated Regulatory Asset Base

sch ref				Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
29		**Total opening RAB value**			316,029		313,092
30	*less*						
31		**Total depreciation**			13,750		13,664
32	*plus*						
33		**Total revaluations**			7,923		7,860
34	*plus*						
35		Assets commissioned (other than below)	Not Required after DY2025	29,670		29,348	
38		Assets acquired from a regulated supplier		–		–	
39		Assets acquired from a related party		–		–	
40		**Assets commissioned**			29,670		29,348
41	*less*						
42		Asset disposals (other than below)		398		398	
43		Asset disposals to a regulated supplier		–		–	
44		Asset disposals to a related party		–		–	
45		**Asset disposals**			398		398
46							
47	*plus*	**Lost and found assets adjustment**			–		–
48							
49	*plus*	**Adjustment resulting from asset allocation**					1,993
50							
51		**Total closing RAB value**			339,474		338,231

52 ** 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.*

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2025**

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

54 4(iii): Calculation of Revaluation Rate and Revaluation of Assets

sch ref							
55							
56		CPI_4					1,299
57		CPI_4^{-4}					1,267
58		Revaluation rate (%)					2.53%
59							
60			**Unallocated RAB ***		**RAB**		
61			**($000)**	**($000)**	**($000)**	**($000)**	
62		Total opening RAB value	316,029		313,092		
63	*less*	Opening value of fully depreciated, disposed and lost assets	2,319		1,884		
64							
65		Total opening RAB value subject to revaluation	313,710		311,208		
66		**Total revaluations**		7,923		7,860	
67							

68 4(iv): Roll Forward of Works Under Construction

sch ref							
69				**Unallocated works under construction**		**Allocated works under construction**	
70		**Works under construction—preceding disclosure year**	Not Required after DY2025		11,175		11,177
71	*plus*	Capital expenditure	Not Required after DY2025	29,076		29,102	
72	*less*	Assets commissioned	Not Required after DY2025	29,670		29,348	
73	*plus*	Adjustment resulting from asset allocation	Not Required after DY2025			–	
74		**Works under construction - current disclosure year**	Not Required after DY2025		10,582		10,931
87							
88		Highest rate of capitalised finance applied					–
89							

90 4(v): Regulatory Depreciation

sch ref						
91			**Unallocated RAB ***		**RAB**	
92			**($000)**	**($000)**	**($000)**	**($000)**
93		Depreciation - standard	10,393		10,393	
94		Depreciation - no standard life assets	3,357		3,271	
95		Depreciation - modified life assets	–		–	
96		Depreciation - alternative depreciation in accordance with CPP	–		–	
97		**Total depreciation**		13,750		13,664
98						

Company Name: **Alpine Energy Limited**
For Year Ended: **31 March 2025**

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

99 **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
101	None	N/A	N/A	N/A	N/A
108					

109 ** include additional rows if needed*

110 **4(vii): Disclosure by Asset Category**

111 **($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
113		**Total opening RAB value**	13,056	5,800	69,097	76,681	69,724	26,800	23,393	11,649	16,892	313,092
114	*less*	Total depreciation	658	160	2,625	2,511	2,101	1,241	693	404	3,271	13,664
115	*plus*	Total revaluations	330	147	1,743	1,935	1,760	677	588	294	386	7,860
116	*plus*	Assets commissioned	–	–	7,426	8,341	4,174	2,758	3,728	142	2,779	29,348
117	*less*	Asset disposals	–	–	8	65	26	6	119	–	174	398
118	*plus*	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
119	*plus*	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–	1,993	1,993
120	*plus*	Asset category transfers	–	–	–	–	–	–	–	–		–
121		**Total closing RAB value**	12,728	5,787	75,633	84,381	73,531	28,988	26,897	11,681	18,605	338,231
122												
123		**Asset Life**										
124		Weighted average remaining asset life	29.4	36.7	33.4	37.6	39.9	25.7	33.6	34.1	37.3	(years)
125		Weighted average expected total asset life	51.0	45.0	42.4	53.2	55.8	45.0	40.4	42.1	41.7	(years)

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2025**

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**		11,374	
9					
10	*plus*	Income not included in regulatory profit / (loss) before tax but taxable	7		*
11		Expenditure or loss in regulatory profit / (loss) before tax but not deductible	99		*
12		Amortisation of initial differences in asset values	2,647		
13		Amortisation of revaluations	2,367		
14		**Total**		5,121	
15					
16	*less*	Total revaluations	7,860		
17		Income included in regulatory profit / (loss) before tax but not taxable	240		*
18		Discretionary discounts and customer rebates	–		
19		Expenditure or loss deductible but not in regulatory profit / (loss) before tax	–		*
20		Notional deductible interest	7,299		
21		**Total**		15,399	
22					
23		**Regulatory taxable income**		1,096	
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income		1,096	
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**		307	
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	29,118		
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		26,471	
41					
42		Opening weighted average remaining useful life of relevant assets (years)		11	
43					

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2025**

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	247,687	
47				
48		Adjusted depreciation	11,297	
49		Total depreciation	13,664	
50		Amortisation of revaluations		2,367
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**	(20,582)	
61				
62	*plus*	Tax effect of adjusted depreciation	3,163	
63				
64	*less*	Tax effect of tax depreciation	3,715	
65				
66	*plus*	Tax effect of other temporary differences*	287	
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	25	
73				
74	*plus*	Deferred tax cost allocation adjustment	–	
75				
76		**Closing deferred tax**		(21,613)
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**	146,856	
84	*less*	Tax depreciation	13,269	
85	*plus*	Regulatory tax asset value of assets commissioned	29,348	
86	*less*	Regulatory tax asset value of asset disposals	489	
87	*plus*	Lost and found assets adjustment	–	
88	*plus*	Adjustment resulting from asset allocation	1,993	
89	*plus*	Other adjustments to the RAB tax value	–	
90		**Closing sum of regulatory tax asset values**		164,439

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2025**

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

5b(i): Summary—Related Party Transactions

sch ref		($000)	($000)
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	401	
18	System operations and network support	–	
19	Non-network solutions provided by a related party or third party	–	
20	**Operational expenditure**		401
21	Consumer connection	–	
22	System growth	–	
23	Asset replacement and renewal (capex)	–	
24	Asset relocations	–	
25	Quality of supply	–	
26	Legislative and regulatory	–	
27	Other reliability, safety and environment	–	
28	**Expenditure on non-network assets**		–
29	**Expenditure on assets**		–
30	Cost of financing		–
31	Value of capital contributions		206
32	Value of vested assets		–
33	**Capital Expenditure**		(206)
34	**Total expenditure**		195
35			
36	**Other related party transactions**		173

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

38	Name of related party	Nature of opex or capex service provided	Total value of transactions ($000)
39	AEL Directors	Business support	401
40		[Select one]	
41		[Select one]	
42		[Select one]	
43		[Select one]	
44		[Select one]	
45		[Select one]	
46		[Select one]	
47		[Select one]	
48		[Select one]	
49		[Select one]	
50		[Select one]	
51		[Select one]	
52		[Select one]	
53		[Select one]	
54	**Total value of related party transactions**		401

55 ** include additional rows if needed*

Company Name	Alpine Energy Limited
For Year Ended	31 March 2025

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

7

8 **5c(i): Qualifying Debt (may be Commission only)**

9

sch ref	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
10									
11	N/A								
12									
13									
14									
15									
16	** include additional rows if needed*						–	–	–

17

18 **5c(ii): Attribution of Term Credit Spread Differential**

19

sch ref			
20	**Gross term credit spread differential**		–
21			
22	Total book value of interest bearing debt	–	
23	Leverage	42%	
24	Average opening and closing RAB values	–	
25	**Attribution Rate (%)**		–
26			
27	**Term credit spread differential allowance**		–

		Company Name	Alpine Energy Limited
		For Year Ended	31 March 2025

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**					
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		2,575			
12	Not directly attributable	–	–	–	–	–
13	**Total attributable to regulated service**		2,575			
14	**Vegetation management**					
15	Directly attributable		1,471			
16	Not directly attributable	–	–	–	–	–
17	**Total attributable to regulated service**		1,471			
18	**Routine and corrective maintenance and inspection**					
19	Directly attributable		3,384			
20	Not directly attributable	–	–	–	–	–
21	**Total attributable to regulated service**		3,384			
22	**Asset replacement and renewal**					
23	Directly attributable		276			
24	Not directly attributable	–	–	–	–	–
25	**Total attributable to regulated service**		276			
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		11,455			
32	Not directly attributable	–	–	–	–	–
33	**Total attributable to regulated service**		11,455			
34	**Business support**					
35	Directly attributable		3,068			
36	Not directly attributable	–	10,778	827	11,605	–
37	**Total attributable to regulated service**		13,846			
38						
39	**Operating costs directly attributable**		22,229			
40	**Operating costs not directly attributable**	–	10,778	827	11,605	–
41	**Operational expenditure**		33,007			
42						

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2025**

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

sch ref		($000)
44	**Pass through and recoverable costs**	
45	**Pass through costs**	
46	Directly attributable	591
47	Not directly attributable	–
48	**Total attributable to regulated service**	591
49	**Recoverable costs**	
50	Directly attributable	14,382
51	Not directly attributable	–
52	**Total attributable to regulated service**	14,382
53		

54 ### 5d(iii): Changes in Cost Allocations* †

sch ref				($000) CY-1	($000) Current Year (CY)
55					
56	**Change in cost allocation 1**				
57	Cost category	N/A	Original allocation	–	–
58	Original allocator or line items	N/A	New allocation	–	–
59	New allocator or line items	N/A	Difference	–	–
60					
61	Rationale for change	N/A			
62					
63					
64					
65	**Change in cost allocation 2**				
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					
74	**Change in cost allocation 3**				
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 Limited**
For Year Ended	**31 March 2025**

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.

5e(i): Regulated Service Asset Values

	Value allocated ($000s) Electricity distribution services
Subtransmission lines	
Directly attributable	12,728
Not directly attributable	–
Total attributable to regulated service	12,728
Subtransmission cables	
Directly attributable	5,787
Not directly attributable	–
Total attributable to regulated service	5,787
Zone substations	
Directly attributable	75,633
Not directly attributable	–
Total attributable to regulated service	75,633
Distribution and LV lines	
Directly attributable	84,381
Not directly attributable	–
Total attributable to regulated service	84,381
Distribution and LV cables	
Directly attributable	73,531
Not directly attributable	–
Total attributable to regulated service	73,531
Distribution substations and transformers	
Directly attributable	28,988
Not directly attributable	–
Total attributable to regulated service	28,988
Distribution switchgear	
Directly attributable	26,897
Not directly attributable	–
Total attributable to regulated service	26,897
Other network assets	
Directly attributable	11,681
Not directly attributable	–
Total attributable to regulated service	11,681
Non-network assets	
Directly attributable	1,994
Not directly attributable	16,611
Total attributable to regulated service	18,605
Regulated service asset value directly attributable	321,620
Regulated service asset value not directly attributable	16,611
Total closing RAB value	338,231

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

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

Change in asset value allocation 2			($000) CY-1	Current Year (CY)
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	–	–
Rationale for change				

Change in asset value allocation 3			($000) CY-1	Current Year (CY)
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	–	–
Rationale for change				

** 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 component*
† include additional rows if needed

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2025**

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		3,255
9		System growth		5,895
10		Asset replacement and renewal		17,945
11		Asset relocations		1,168
12		Reliability, safety and environment:		
13		Quality of supply	310	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	1,567	
16		**Total reliability, safety and environment**		1,877
17		**Expenditure on network assets**		30,139
18		Expenditure on non-network assets		1,836
19				
20		**Expenditure on assets**		31,975
21	*plus*	Cost of financing		–
22	*less*	Value of capital contributions		2,873
23	*plus*	Value of vested assets		–
24				
25		**Capital expenditure**		29,102
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		14
29		Research and development		–
31		**6a(iii): Consumer Connection**		
32		*Consumer types defined by EDB**	**($000)**	**($000)**
33		CC - Commercial	1,566	
34		CC - HV alterations	8	
35		CC - Irrigation	120	
36		CC - LV alterations	18	
		CC - Residential	787	
37		CC - Subdivision	756	
38		** include additional rows if needed*		
39		**Consumer connection expenditure**		3,255
40				
41	*less*	Capital contributions funding consumer connection expenditure	2,617	
42		**Consumer connection less capital contributions**		637
43		**6a(iv): System Growth and Asset Replacement and Renewal**		
44			**System Growth**	**Asset Replacement and Renewal**
45			**($000)**	**($000)**
46		Subtransmission	–	40
47		Zone substations	4,196	733
48		Distribution and LV lines	181	8,954
49		Distribution and LV cables	1,097	3,070
50		Distribution substations and transformers	50	2,708
51		Distribution switchgear	370	2,235
52		Other network assets	–	205
53		**System growth and asset replacement and renewal expenditure**	5,895	17,945
54	*less*	Capital contributions funding system growth and asset replacement and renewal	4	238
55		**System growth and asset replacement and renewal less capital contributions**	5,891	17,708
56				
57		**6a(v): Asset Relocations**		
58		*Project or programme**	**($000)**	**($000)**
59		Undergrounding of Pages road - Centennial Park	1,124	
60				
61				
62				
63				
64		** include additional rows if needed*		
65		All other projects or programmes - asset relocations	44	
66		**Asset relocations expenditure**		1,168
67	*less*	Capital contributions funding asset relocations	14	
68		**Asset relocations less capital contributions**		1,153

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2025**

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		Purchase of 2 Network Generators	310	
73				
74				
75				
76				
77		** include additional rows if needed*		
78		All other projects programmes - quality of supply		
79		**Quality of supply expenditure**		310
80	*less*	Capital contributions funding quality of supply	–	
81		**Quality of supply less capital contributions**		310
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		
91		**Legislative and regulatory expenditure**		–
92	*less*	Capital contributions funding legislative and regulatory	–	
93		**Legislative and regulatory less capital contributions**		–
94	**6a(viii): Other Reliability, Safety and Environment**			
95		*Project or programme**	**($000)**	**($000)**
96		Temuka Ripple Plant Replacement & Upgrade	376	
97				
98				
99				
100				
101		** include additional rows if needed*		
102		All other projects or programmes - other reliability, safety and environment	1,191	
103		**Other reliability, safety and environment expenditure**		1,567
104	*less*	Capital contributions funding other reliability, safety and environment	–	
105		**Other reliability, safety and environment less capital contributions**		1,567
106				
107	**6a(ix): Non-Network Assets**			
108	**Routine expenditure**			
109		*Project or programme**	**($000)**	**($000)**
111		Plant & Equipment	2,220	
112		Land & Building	74	
113		Computer & Software	(665)	
114				
115		** include additional rows if needed*		
116		All other projects or programmes - routine expenditure	–	
117		**Routine expenditure**		1,629
118	**Atypical expenditure**			
119		*Project or programme**	**($000)**	**($000)**
120		*No material projects*		
121				
122				
123				
124				
125		** include additional rows if needed*		
126		All other projects or programmes - atypical expenditure	207	
127		**Atypical expenditure**		207
128				
129		**Expenditure on non-network assets**		1,836

	Company Name	Alpine Energy Limited
	For Year Ended	31 March 2025

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** *Required for DY2025 only*		**($000)**	**($000)**
8	Service interruptions and emergencies		2,575	
9	Vegetation management		1,471	
10	Routine and corrective maintenance and inspection		3,384	
11	Asset replacement and renewal		276	
12	**Network opex**			7,706
13	Non-network solutions provided by a related party or third party	*Required for DY2025 only*	–	
14	System operations and network support		11,455	
15	Business support		13,846	
16	**Non-network opex**			25,301
17				
18	**Operational expenditure**			33,007
40	**6b(ii): Subcomponents of Operational Expenditure (where known)**			
41	Energy efficiency and demand side management, reduction of energy losses			–
42	Direct billing*			–
43	Research and development			–
44	Insurance			667
45	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*			

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2025**

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	69,463	65,148	(6%)
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	7,310	3,255	(55%)
11	System growth	8,840	5,895	(33%)
12	Asset replacement and renewal	16,968	17,945	6%
13	Asset relocations	250	1,168	367%
14	Reliability, safety and environment:			
15	Quality of supply	–	310	–
16	Legislative and regulatory	800	–	(100%)
17	Other reliability, safety and environment	2,535	1,567	(38%)
18	**Total reliability, safety and environment**	3,335	1,877	(44%)
19	**Expenditure on network assets**	36,703	30,139	(18%)
20	Expenditure on non-network assets	2,292	1,836	(20%)
21	Expenditure on assets	38,995	31,975	(18%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	2,209	2,575	17%
24	Vegetation management	1,550	1,471	(5%)
25	Routine and corrective maintenance and inspection	3,330	3,384	2%
26	Asset replacement and renewal	342	276	(19%)
27	**Network opex**	7,431	7,706	4%
28	Non-network solutions provided by a related party or third party	–	–	–
29	System operations and network support	11,932	11,455	(4%)
30	Business support	20,800	13,846	(33%)
31	**Non-network opex**	32,732	25,301	(23%)
32	**Operational expenditure**	40,163	33,007	(18%)
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	50	14	(71%)
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	628	667	6%
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 Limited
For Year Ended: 31 March 2025
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(i): Billed Quantities by Price Component

Billed quantities 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	Number of ICP's of Fixed charge		MWh of Variable Day charge		MWh of Variable Night charge		Demand (MW)	
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)	Distribution billed quantity	Transmission billed quantity	Distribution billed quantity	Transmission billed quantity	Distribution billed quantity	Transmission billed quantity	Distribution billed quantity	Transmission billed quantity
LOWHCA	Residential	Standard	2,291	14,374	2,291	2,291	10,061	10,061	4,312	4,312	–	–
LOWLCA	Residential	Standard	10,863	61,105	10,863	10,863	42,773	42,773	18,331	18,331	–	–
LOWUHCA	Residential	Standard	23	156	23	23	109	109	47	47	–	–
LOWULCA	Residential	Standard	57	383	57	57	268	268	115	115	–	–
015HCA	Residential	Standard	5,920	60,113	5,920	5,920	42,079	42,079	18,034	18,034	–	–
015LCA	Residential	Standard	11,484	102,528	11,484	11,484	71,770	71,770	30,758	30,758	–	–
015UHCA	Residential	Standard	41	622	41	41	436	436	187	187	–	–
015ULCA	Residential	Standard	46	422	46	46	295	295	126	126	–	–
360HCA	Commercial	Standard	530	10,990	530	530	7,693	7,693	3,297	3,297	–	–
360LCA	Commercial	Standard	743	21,617	743	743	15,132	15,132	6,485	6,485	–	–
360UHCA	Commercial	Standard	14	460	14	14	322	322	138	138	–	–
360ULCA	Commercial	Standard	17	452	17	17	317	317	136	136	–	–
ASSHCA	Industrial	Standard	1,319	120,929	1,319	1,319	84,650	84,650	36,279	36,279	115	115
ASSLCA	Industrial	Standard	415	42,725	415	415	29,908	29,908	12,818	12,818	39	39
TOU400HCA	Industrial	Standard	37	23,552	37	37	16,493	16,493	7,059	7,059	8	8
TOU400LCA	Industrial	Standard	99	100,326	99	99	69,051	69,051	31,275	31,275	23	23
TOU11HCA	Industrial	Standard	5	53,912	5	5	38,949	38,949	14,962	14,962	11	11
TOU11LCA	Industrial	Standard	5	11,982	5	5	8,359	8,359	3,623	3,623	4	4
Individual Direct Billed	Industrial	Non-standard	12	202,335	12	12	133,864	133,864	68,470	68,470	–	–
Add extra rows for additional consumer groups or price category codes as necessary												
		Standard consumer totals	33,904	626,648	33,904	33,904	438,666	438,666	187,982	187,982	199	199
		Non-standard consumer totals	12	202,335	12	12	133,864	133,864	68,470	68,470	–	–
		Total for all consumers	33,916	828,983	33,916	33,916	572,531	572,531	256,452	256,452	199	199

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

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

Consumer discounts ($000)

			Standardised price component	[Select one]				
			EDB defined price component	N/A				
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	$1,914	–	–	–	$1,574	$340
LOWLCA	Residential	Standard	$7,829	–	–	–	$6,388	$1,440
LOWUHCA	Residential	Standard	$21	–	–	–	$19	$3
LOWULCA	Residential	Standard	$48	–	–	–	$41	$7
015HCA	Residential	Standard	$6,642	–	–	–	$5,199	$1,443
015LCA	Residential	Standard	$11,872	–	–	–	$9,064	$2,808
015UHCA	Residential	Standard	$51	–	–	–	$39	$11
015ULCA	Residential	Standard	$53	–	–	–	$39	$13
360HCA	Commercial	Standard	$1,958	–	–	–	$1,560	$398
360LCA	Commercial	Standard	$2,578	–	–	–	$2,020	$558
360UHCA	Commercial	Standard	$53	–	–	–	$42	$11
360ULCA	Commercial	Standard	$57	–	–	–	$44	$13
ASSHCA	Industrial	Standard	$13,040	–	–	–	$10,770	$2,270
ASSLCA	Industrial	Standard	$3,991	–	–	–	$3,246	$745
TOU400HCA	Industrial	Standard	$1,733	–	–	–	$1,299	$434
TOU400LCA	Industrial	Standard	$4,751	–	–	–	$3,512	$1,239
TOU11HCA	Industrial	Standard	$2,440	–	–	–	$2,052	$388
TOU11LCA	Industrial	Standard	$733	–	–	–	$594	$138
Individual Direct Billed	Industrial	Non-standard	$5,387	–	–	–	$3,309	$2,078
Add extra rows for additional consumer groups or price category codes as necessary								
		Standard consumer totals	$59,761	–	–	–	$47,502	$12,259
		Non-standard consumer totals	$5,387	–	–	–	$3,309	$2,078
		Total for all consumers	$65,148	–	–	–	$50,811	$14,337

Line charge revenues ($000) by price component

Standardised price component	Other charge [see EDB defined price component below]			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	Fixed charge - $/annum			Variable Day charge - $/MWh			Variable Night charge - $/MWh			Demand - $/MWh/annum		
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	$502	–	$502	$723	$306	$1,029	$349	$34	$383	–	–	–
LOWLCA	$2,370	–	$2,370	$2,693	$1,296	$3,989	$1,325	$144	$1,469	–	–	–
LOWUHCA	$6	–	$6	$9	$2	$11	$4	$0	$4	–	–	–
LOWULCA	$13	–	$13	$19	$6	$26	$9	$1	$9	–	–	–
015HCA	$4,435	$1,443	$5,878	$688	–	$688	$77	–	$77	–	–	–
015LCA	$7,760	$2,808	$10,568	$1,173	–	$1,173	$131	–	$131	–	–	–
015UHCA	$31	$11	$43	$7	–	$7	$1	–	$1	–	–	–
015ULCA	$34	$13	$47	$5	–	$5	$1	–	$1	–	–	–
360HCA	$1,420	$398	$1,818	$126	–	$126	$14	–	$14	–	–	–
360LCA	$1,745	$558	$2,303	$247	–	$247	$28	–	$28	–	–	–
360UHCA	$36	$11	$47	$5	–	$5	$1	–	$1	–	–	–
360ULCA	$38	$13	$51	$5	–	$5	$1	–	$1	–	–	–
ASSHCA	$1,703	$1,085	$2,789	$1,384	–	$1,384	$154	–	$154	$7,528	$1,185	$8,713
ASSLCA	$476	$342	$817	$489	–	$489	$54	–	$54	$2,227	$403	$2,630
TOU400HCA	$36	$45	$81	$148	–	$148	$9	–	$9	$1,107	$389	$1,495
TOU400LCA	$86	$121	$207	$619	–	$619	$40	–	$40	$2,766	$1,118	$3,884
TOU11HCA	$6	$8	$14	$342	–	$342	$16	–	$16	$1,687	$379	$2,067
TOU11LCA	$4	$6	$10	$74	–	$74	$4	–	$4	$512	$133	$645
Individual Direct Billed	$3,309	$2,078	$5,387	–	–	–	–	–	–	–	–	–
Standard consumer totals	$20,701	$6,862	$27,564	$8,756	$1,611	$10,367	$2,217	$179	$2,396	$15,828	$3,607	$19,435
Non-standard consumer totals	$3,309	$2,078	$5,387	–	–	–	–	–	–	–	–	–
Total for all consumers	$24,010	$8,940	$32,951	$8,756	$1,611	$10,367	$2,217	$179	$2,396	$15,828	$3,607	$19,435

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	12

Company Name	Alpine Energy Limited
For Year Ended	31 March 2025
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

sch ref	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
8								
9	All	Overhead Line	Concrete poles / steel structure	No.	25,634	25,935	301	3
10	All	Overhead Line	Wood poles	No.	18,719	18,491	(228)	3
11	All	Overhead Line	Other pole types	No.	271	263	(8)	3
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	249	250	1	3
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	33	34	1	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.	24	28	4	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	113	–	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	26	–	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	170	188	18	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.	31	32	1	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2,891	2,919	28	3
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	7	7	–	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	341	399	58	2
39	HV	Distribution Cable	Distribution UG PILC	km	136	135	(1)	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.	61	60	(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.	6,959	6,976	17	2
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	72	73	1	4
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	489	490	1	4
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	5,060	5,069	9	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	1,140	1,141	1	4
48	HV	Distribution Transformer	Voltage regulators	No.	69	69	–	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	N/A
50	LV	LV Line	LV OH Conductor	km	345	347	2	3
51	LV	LV Cable	LV UG Cable	km	380	381	1	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	–	N/A
53	LV	Connections	OH/UG consumer service connections	No.	38,828	34,938	(3,890)	3
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	455	507	52	3
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	514	629	115	3
56	All	Capacitor Banks	Capacitors including controls	No	11	11	–	4
57	All	Load Control	Centralised plant	Lot	7	7	–	4
58	All	Load Control	Relays	No	–	–	–	N/A
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name	Alpine Energy Limited
For Year Ended	31 March 2025
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	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.		199	3,302	5,326	3,700	2,414	1,547	140	226	249	434	449	816	303	310	307	333	321	141	384	481	385	313	370	229	281	323	480	463	497	528	414	140	130	25,935		3
11	All	Overhead Line	Wood poles	No.		7	2,371	1,547	1,991	1,705	1,820	169	200	450	453	400	559	343	507	700	624	350	233	368	342	487	278	241	151	120	161	202	190	258	247	326	162	529	18,491		3
12	All	Overhead Line	Other pole types	No.			38	49	31	18	14	7			2	1				2	1	3	2	2	6	1												86	263		3
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km			4	36	43	11	55	5		8	14	0	–	1				1	0	0	21	31	0	12	0	0	4	3			0	0			250		3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km																																			–		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					2	1						4	1					1	1		1			1		1	3	28		4
25	HV	Zone substation Buildings	Zone substations 110kV+	No.																		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.				11	8	12	7									1		1	3	6	11	8	6	1	12		7	3	1	6	9				113		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	3					2						1		2	1	3	1	3	2		1	1			3				26		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		1					2		2		2	1	2	3		1	1				2			3	2	1	2	1	1	32		4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	6	0	841	473	340	236	151	2	28	34	74	62	134	34	48	54	58	37	17	30	39	37	28	29	12	9	10	14	25	20	8	4	6	19	2,919		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	4	12	11	1	6	14	11	7	11	20	15	20	15	14	18	26	22	14	17	14	17	24	13	6	13	15	21	6	1	6	399		2
40	HV	Distribution Cable	Distribution UG PILC	km				8	40	53	30	2	1	–	0	1	1	0	0	0	0	0		0										–					135		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.							2	2	2				4	1	1		1	6	2	3		8	5	1	2	6	4	1	6		1	1	1		60		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	348	392	331	281	277	27	63	82	147	116	165	127	158	252	267	203	167	261	259	259	335	222	575	335	216	250	195	196	153	171	138	5	6,976		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.				7	39	26	29	2	12	10	9	11	13	11	9	9	10	15	8	6	5	9	25	28	24	39	8	18	28	16	33	13	17	1	490		4
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	2	21	354	607	535	387	500	60	127	132	140	142	74	136	147	108	227	91	75	105	76	163	128	94	73	114	62	61	74	85	81	44	39	5	5,069		4
48	HV	Distribution Transformer	Ground Mounted Transformer	No.		1	10	41	134	98	32	6	20	35	46	24	47	52	38	62	58	9	10	28	19	33	47	47	40	36	31	14	36	30	32	12	12	1	1,141		4
49	HV	Distribution Transformer	Voltage regulators	No.										2	2				4	10	21	2	5		4	6		4		2	4	2						1	69		4
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.																																			–		N/A
51	LV	LV Line	LV OH Conductor	km	0		55	118	100	39	18	1	1	1	1	1	0	1	0	1	1	1	1	0	1	0	1	0	0	1	1	0	0	0	0	1	1	1	347		3
52	LV	LV Cable	LV UG Cable	km			0	13	72	89	67	3	4	4	4	7	7	9	8	6	7	8	5	3	3	3	3	8	4	7	7	4	7	7	7	3	2	1	381		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	1	26,743	353	432	449	416	437	473	377	263	312	310	383	364	373	347	315	314	338	322	329	341	267	245	432	34,938		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	45	23	7	4	4		2	17		2	51	507		3
56	All	SCADA and communications	SCADA and communications equipment operating as a single sys	Lot						5	67												3	57	15	7	27	38	15	36	16	5	64	55	79	21	49	70	629		3
57	All	Capacitor Banks	Capacitors including controls	No																6	1		1	1									1					1	11		4
58	All	Load Control	Centralised plant	Lot					1						1		1													2		1						1	7		4
59	All	Load Control	Relays	No																																			–		N/A
60	All	Civils	Cable Tunnels	km																																			–		N/A

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2025**
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

sch ref					
10					
11	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**	
12	> 66kV	1		1	
13	50kV & 66kV			–	
14	33kV	250	34	284	
15	SWER (all SWER voltages)		7	7	
16	22kV (other than SWER)	145	17	162	
17	6.6kV to 11kV (inclusive—other than SWER)	2,742	462	3,203	
18	Low voltage (< 1kV)	346	380	726	
19	**Total circuit length (for supply)**	3,484	900	4,384	
20					
21	Dedicated street lighting circuit length (km)			–	
22	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			82	
23					
24	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**		
25	Urban	274	8%		
26	Rural	2,894	83%		
27	Remote only	220	6%		
28	Rugged only	86	2%		
29	Remote and rugged	9	0%		
30	Unallocated overhead lines		–		
31	**Total overhead length**	3,484	100%		
32					
33		**Circuit length (km)**	**(% of total circuit length)**		
34	Length of circuit within 10km of coastline or geothermal areas (where known)	1,782	41%		
35					
36		**Circuit length (km)**	**(% of total overhead length)**		
37	Overhead circuit requiring vegetation management	757	22%		*Not required after DY2025*
38		**Total newly identified throughout the disclosure year**	**Total remaining at high risk at the disclosure year-end**		
39	Number of overhead circuit sites at high risk from vegetation damage		–		*Not required before DY2026*
40					
41	**Breakdown of overhead circuit sites at high risk from vegetation damage at disclosure year-end**				
42	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		
43	[Single tree]				*Not required before DY2026*
44	[Single tree - Urban]				*Not required before DY2026*
45	[Single tree - Rural]				*Not required before DY2026*
46	[Row of trees]				*Not required before DY2026*
47	[Span between two poles (X metres)]				*Not required before DY2026*
48	[Other]				*Not required before DY2026*
49	**Total number of sites**	–	–		*Not required before DY2026*
50	** Insert new rows in table above Total line as necessary*				

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2025**

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

8	**Location ***	**Average number of ICPs in disclosure year**	**Line charge revenue ($000)**
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 Limited**
For Year Ended	**31 March 2025**
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

9e(i): Consumer Connections and Decommissionings

Number of ICPs connected during year by consumer type

sch ref	*Consumer types defined by EDB**	Number of connections (ICPs)
11	Low Charge	30
12	Low Uncontrolled	36
13	015	275
14	015 Uncontrolled	30
15	360	15
16	360 Uncontrolled	3
17	Assessed	9
18	TOU 400V	3
19	TOU 11kV	–
20	IND	–
21	** include additional rows if needed*	
22	**Connections total**	401

Number of ICPs decommissioned during year by consumer type

sch ref	*Consumer types defined by EDB**	Number of decommissionings
26	Low Charge	14
27	Low Uncontrolled	–
28	015	121
29	015 Uncontrolled	–
30	360	11
31	360 Uncontrolled	–
32	Assessed	8
33	TOU 400V	1
34	TOU 11kV	1
35	IND	–
36	** include additional rows if needed*	
37	**Decommissionings total**	156

Distributed generation

sch ref			
40	Number of connections made in year	154	**connections**
41	Capacity of distributed generation installed in year	1.07	**MVA**

9e(ii): System Demand

sch ref			Demand at time of maximum coincident demand (MW)
46		**Maximum coincident system demand**	
47		GXP demand	149
48	*plus*	Distributed generation output at HV and above	5
49		**Maximum coincident system demand**	154
50	*less*	Net transfers to (from) other EDBs at HV and above	–
51		**Demand on system for supply to consumers' connection points**	154

sch ref		**Electricity volumes carried**	Energy (GWh)	
53		Electricity supplied from GXPs	850	
54	*less*	Electricity exports to GXPs	10	
55	*plus*	Electricity supplied from distributed generation	19	
56	*less*	Net electricity supplied to (from) other EDBs	–	
57		**Electricity entering system for supply to consumers' connection points**	859	
58	*less*	Total energy delivered to ICPs	829	
59		**Electricity losses (loss ratio)**	30	3.4%
61		**Load factor**	0.64	

9e(iii): Transformer Capacity

sch ref		(MVA)
64	Distribution transformer capacity (EDB owned)	628
65	Distribution transformer capacity (Non-EDB owned)	16
66	**Total distribution transformer capacity**	645

sch ref		(MVA)
69	Zone substation transformer capacity (EDB owned)	396
70	Zone substation transformer capacity (Non-EDB owned)	–
71	**Total zone substation transformer capacity**	396

Company Name	Alpine Energy Limited
For Year Ended	31 March 2025
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)	40	
11	Class B (planned interruptions on the network)	1,045	
12	Class C (unplanned interruptions on the network)	523	
13	Class D (unplanned interruptions by Transpower)	75	
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)	1	
19	**Total**	1,684	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	355	168
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)	0.1406	23.33
26	Class B (planned interruptions on the network)	0.4489	129.67
27	Class C (unplanned interruptions on the network)	1.0925	106.11
28	Class D (unplanned interruptions by Transpower)	0.1765	100.08
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)	0.0001	0.01
34	**Total**	1.8586	359.20
35			
36	**Transitional SAIFI and SAIDI (previous method)**	**SAIFI**	**SAIDI**
37	Class B (planned interruptions on the network)	N/A	N/A
38	Class C (unplanned interruptions on the network)	N/A	N/A
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 Limited**
For Year Ended	**31 March 2025**
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.

41 ### 10(ii): Class C Interruptions and Duration by Cause

	Cause	SAIFI	SAIDI
44	Lightning	0.0316	4.85
45	Vegetation	0.0638	4.45
46	Adverse weather	0.1511	15.72
47	Adverse environment	0.0099	2.09
48	Third party interference	0.2690	22.53
49	Wildlife	0.0952	9.51
50	Human error	0.0017	0.03
51	Defective equipment	0.3330	36.12
52	Other cause	–	–
53	Unknown	0.1373	11.89

	Breakdown of third party interference	SAIFI	SAIDI
56	Dig-in	0.0000	0.44
57	Overhead contact	0.0593	4.00
58	Vandalism	–	–
59	Vehicle damage	0.1570	13.81
60	Other	0.0527	4.28

66 ### 10(iii): Class B Interruptions and Duration by Main Equipment Involved

	Main equipment involved	SAIFI	SAIDI
69	Subtransmission lines	–	–
70	Subtransmission cables	–	–
71	Subtransmission other	–	–
72	Distribution lines (excluding LV)	0.3563	102.53
73	Distribution cables (excluding LV)	0.0926	27.15
74	Distribution other (excluding LV)	–	–

75 ### 10(iv): Class C Interruptions and Duration by Main Equipment Involved

	Main equipment involved	SAIFI	SAIDI
78	Subtransmission lines	–	–
79	Subtransmission cables	0.0009	0.00
80	Subtransmission other	–	–
81	Distribution lines (excluding LV)	1.0119	98.66
82	Distribution cables (excluding LV)	0.0776	7.22
83	Distribution other (excluding LV)	0.0021	0.23

84 ### 10(v): Fault Rate

	Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
86	Subtransmission lines	2	251	0.80
87	Subtransmission cables	1	34	2.94
88	Subtransmission other	–		
89	Distribution lines (excluding LV)	549	2,887	19.02
90	Distribution cables (excluding LV)	39	486	8.02
91	Distribution other (excluding LV)	3		
92	**Total**	594		

Company Name	**Alpine Energy Limited**
For Year Ended	**31 March 2025**
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

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

SAIDI

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)
1	Geraldine Township	11.9976	18	Defective equipment	26	1408	
2	Hadlow	7.4070	25	Defective equipment	163	888	
3	Woodbury	7.2692	28	Lightning	153	687	
4	Temuka East	5.5408	2	Defective equipment	19	1397	
5	Cave	5.4256	40	Adverse weather	208	397	
6	Normanby	5.4234	18	Third party interference	74	546	
7	Rolleston Road	4.6431	21	Defective equipment	36	1	
8	Waihaorunga	4.3087	11	Defective equipment	22	241	
9	Fairlie Rural	4.2878	24	Defective equipment	212	674	
10	Totara Valley	4.2878	12	Third party interference	69	546	
11	Otaio	3.9431	16	Defective equipment	116	320	
12	Morven	3.8835	29	Wildlife	111	312	
13	Waitohi	3.8725	12	Third party interference	102	286	
14	Tawai	3.4759	12	Third party interference	54	317	

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

SAIFI

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)
1	Geraldine Township	0.1529	18	Defective equipment	26	1408	
2	Waihaorunga	0.0842	11	Defective equipment	22	241	
3	Normanby	0.0597	18	Third party interference	74	546	
4	Totara Valley	0.0587	12	Third party interference	69	546	
5	Hadlow	0.0548	25	Defective equipment	163	888	
6	Rolleston Road	0.0522	21	Defective equipment	36	1	
7	Fairlie Rural	0.0457	24	Defective equipment	212	674	
8	Tawai	0.0433	12	Third party interference	54	317	
9	Temuka East	0.0431	2	Defective equipment	19	1397	
10	Cave	0.0424	40	Adverse weather	208	397	
11	Morven	0.0392	29	Wildlife	111	312	
12	Otaio	0.0385	16	Defective equipment	116	320	
13	Grants Road	0.0353	3	Third party interference	8	1116	
14	Woodbury	0.0277	28	Lightning	153	687	

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

Customer Impact

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)
1	Rolleston Road	157511.0000	21	Defective equipment	36	1	
2	Waikakahi	1189.9011	20	Lightning	142	91	
3	Waihaorunga	606.5062	11	Defective equipment	22	241	
4	M159	599.8824	6	Defective equipment	5	68	
5	M158	523.1333	3	Cause unknown	5	15	
6	Mahan Road	506.6667	6	Defective equipment	33	90	
7	Rangitata	500.8792	22	Cause unknown	48	149	
8	Cave	463.6222	40	Adverse weather	208	397	
9	Waitohi	459.3322	12	Third party interference	102	286	
10	Morven	422.9076	29	Wildlife	111	312	
11	Otaio	418.0156	16	Defective equipment	116	320	
12	Tawai	371.9748	12	Third party interference	54	317	
13	Woodbury	358.9549	28	Lightning	153	687	
14	Normanby	336.9689	18	Third party interference	74	546	

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