Appendices

Appendix A – Forecast of connection point maximum demands
Appendix B – Powerlink's forecasting methodology
Appendix C – Estimated network power flows
Appendix D – Limit equations
Appendix E – Indicative short circuit currents
Appendix F – Abbreviations

Appendices

Appendix A – Forecast of connection point maximum demands

Tables A.1 to A.6 show 10-year forecasts of native summer and winter demand at connection point peak. These forecasts have been supplied by Powerlink customers.

The connection point reactive power (MVAr) forecast includes the customer's downstream capacitive compensation.

Groupings of some connection points are used to protect the confidentiality of specific customer loads.

In tables A.1 to A.6 the zones in which connection points are located are abbreviated as follows:

FN	Far North zone
R	Ross zone
N	North zone
CW	Central West zone
G	Gladstone zone
WB	Wide Bay zone
S	Surat zone
B	Bulli zone
SW	South West zone
M	Moreton zone
GC	Gold Coast zone

Table A.1 Ergon Energy connection point forecast of summer native maximum demand

Connection point	Voltage (kV)	Zone	2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25		2025/26		2026/27(1)	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Alan Sherriff	132	R	26	13	26	13	26	13	26	13	27	13	27	13	27	13	27	13	27	13	28	14
Aligator Creek (Louisa Creek)	132	N	39	12	39	12	38	11	38	11	38	11	37	11	37	11	36	11	36	11	36	11
Alligator Creek	33	N	38	14	38	14	38	14	38	14	38	14	38	14	37	14	38	14	38	14	38	14
Biloela	66	CW	32	6	32	6	32	6	32	6	32	6	32	6	32	6	32	6	32	6	32	6
Blackwater	132	CW	29	17	29	17	28	17	28	17	28	17	27	17	27	16	27	16	27	16	26	16
Blackwater	66	CW	98	11	98	11	95	11	95	11	98	11	100	12	98	12	98	11	97	11	97	11
Bowen North	66	R	23	8	23	8	23	8	31	11	31	11	31	10	30	10	30	10	30	10	30	10
Bulli Creek (Waggamba)	132	B	19	3	19	3	19	3	19	3	19	3	19	3	18	3	18	3	18	3	18	3
Cairns	22	FN	47	0	47	0	46	0	46	0	45	0	45	0	44	0	44	0	44	0	44	0
Cairns City	132	FN	58	30	58	30	57	30	57	30	56	29	56	29	55	29	54	28	54	28	54	28
Calliope River	132	G	40	20	47	24	44	22	43	22	43	22	43	22	42	21	42	21	41	21	41	21
Cardwell	22	R	5	3	5	3	5	3	5	3	5	3	5	3	5	3	5	3	5	3	5	3
Chinchilla	132	SW	18	9	18	9	18	9	18	9	18	9	18	9	18	9	18	9	18	9	18	9
Clare South	66	R	81	26	82	26	80	26	81	26	80	26	77	25	76	24	76	24	76	24	76	24
Collinsville	33	N	15	8	15	8	15	8	16	8	16	8	16	8	16	8	16	8	16	8	16	8
Columboola	132	SW	60	9	61	9	60	9	60	9	59	9	59	9	58	8	58	8	58	8	58	8
Dan Gleeson	66	R	111	35	113	35	111	35	112	35	112	35	107	32	106	31	107	31	107	31	107	31
Dysart	66	CW	47	8	47	8	46	8	46	8	46	8	45	8	45	8	44	8	44	8	44	8
Edmonton	22	FN	46	10	47	10	47	10	47	10	48	10	48	10	48	10	48	10	49	10	49	10
Egans Hill	66	CW	70	13	71	13	71	13	72	13	72	13	72	13	72	13	72	13	73	13	73	14
El Arish	22	FN	5	1	5	1	5	1	5	1	6	1	6	1	6	1	6	1	6	1	6	1
Garbutt	66	R	105	33	106	33	105	33	106	33	106	33	101	30	100	29	100	29	101	29	101	29

Table A.1 Ergon Energy connection point forecast of summer native maximum demand *(continued)*

Connection point	Voltage (kV)	Zone	2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25		2025/26		2026/27(1)	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Gin Gin	132	WB	135	16	135	16	133	16	133	16	131	16	131	16	129	16	128	15	128	15	127	15
Gladstone South	66	G	59	22	60	22	61	23	62	23	62	23	63	23	63	23	63	23	64	24	65	24
Ingham	66	R	19	5	19	5	19	5	19	5	19	5	19	5	18	5	18	5	18	5	18	5
Innisfail	22	FN	28	14	28	14	27	14	27	14	27	14	27	14	26	13	26	13	26	13	26	13
Kamerunga	22	FN	62	21	63	21	62	21	63	21	63	21	63	22	62	21	63	22	63	22	64	22
Lilyvale (Barcaldine & Clermont)	132	CW	34	6	34	6	34	5	34	5	33	5	33	5	33	5	33	5	33	5	33	5
Lilyvale	66	CW	138	60	139	60	144	63	145	63	152	66	152	66	150	65	149	65	149	65	149	65
Mackay	33	N	88	36	88	36	87	36	87	36	87	36	87	36	86	35	85	35	85	35	85	35
Middle Ridge	110	SW	207	30	208	30	205	30	206	30	204	30	204	30	201	29	200	29	200	29	200	29
Middle Ridge (Postmans Ridge)	110	M	9	4	9	4	9	4	9	4	9	4	9	4	9	4	9	4	9	4	9	4
Moranbah (Broadlea)	132	N	38	12	38	12	37	12	37	12	37	12	39	13	41	13	40	13	40	13	40	13
Moranbah	66 and 11	N	123	37	123	37	120	36	120	36	118	36	136	41	152	46	150	45	150	45	149	45
Moura	66	CW	58	19	58	19	57	19	57	19	57	19	57	19	56	19	56	18	56	18	56	18
Nebo	11	N	3	1	3	1	3	1	3	1	3	1	3	1	3	1	3	1	3	1	3	1
Newlands	66	N	33	13	33	13	34	14	37	15	37	14	36	14	36	14	35	14	35	14	35	14
Oakey	110	SW	28	6	28	6	28	6	28	6	27	5	27	5	27	5	26	5	26	5	26	5
Pandoin	66	CW	41	8	42	8	42	8	42	8	42	8	43	8	42	8	42	8	43	8	43	8
Pioneer Valley	66	N	62	28	62	28	61	27	61	27	61	27	61	27	60	27	60	27	60	27	60	27
Proserpine	66	N	48	17	48	17	48	17	48	17	48	17	48	17	47	16	47	16	47	16	47	16

Table A.1 Ergon Energy connection point forecast of summer native maximum demand *(continued)*

Connection point	Voltage (kV)	Zone	2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25		2025/26		2026/27(1)	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Rockhampton	66	CW	98	18	98	18	96	18	96	18	95	18	95	18	93	17	93	17	93	17	93	17
Ross (Kidston, Milchester and Georgetown)	132	R	40	15	41	15	40	15	41	15	41	15	41	15	41	15	41	15	41	15	41	15
Stony Creek	132	N	6	3	6	3	6	3	6	3	6	3	6	3	6	3	6	3	6	3	6	3
Tangkam	110	SW	82	26	84	26	84	26	85	27	84	26	85	27	84	26	84	26	84	26	85	27
Tarong	66	SW	40	16	40	16	39	16	39	16	39	16	39	16	38	15	38	15	38	15	38	15
Teebar Creek (Isis and Maryborough)	132	WB	117	37	118	37	116	36	116	36	115	36	115	36	113	35	113	35	113	35	113	35
Townsville East	66	R	48	15	49	15	48	15	49	15	48	15	46	14	46	13	46	13	46	13	46	13
Townsville South	66	R	104	33	103	32	101	32	100	31	99	31	94	28	91	27	91	26	90	26	89	26
Tully	22	R	15	7	15	7	14	7	14	7	14	7	14	7	14	7	14	7	14	7	14	7
Turkinje (Craiglie and Lakeland)	132	FN	20	6	20	6	20	6	20	6	20	6	20	6	20	6	19	6	20	6	20	6
Turkinje	66	FN	60	16	60	16	62	16	68	18	67	18	67	18	66	17	65	17	65	17	65	17
Woolooga (Kilkivan)	132	WB	25	3	25	3	25	3	25	3	25	3	25	3	24	3	24	3	24	3	24	3
Woree (Cairns North)	132	FN	47	21	49	21	50	22	51	23	53	23	54	24	55	24	56	25	58	25	59	26
Yarwun (Boat Creek)	132	G	39	23	39	23	38	22	38	22	38	23	39	23	39	23	38	23	38	23	38	23
Hail Creek and King Creek	Various	Various	40	9	40	9	39	9	39	9	39	9	39	9	38	9	38	9	38	9	37	9

Note:

(1) Connection point loads for summer 2026/27 have been extrapolated.

Table A.2 Ergon connection point forecast of winter native maximum demand

Connection point	Voltage (kV)	Zone	2017		2018		2019		2020		2021		2022		2023		2024		2025		2026	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Alan Sherriff	132	R	23	12	23	12	23	12	23	12	23	12	23	12	23	12	23	12	23	12	23	12
Alligator Creek (Louisa Creek)	132	N	41	13	41	13	41	13	39	13	40	13	39	13	39	13	39	12	39	12	38	12
Alligator Creek	33	N	37	14	37	14	37	14	36	13	37	14	36	13	36	13	36	13	36	13	36	13
Biloela	66	CW	32	4	32	4	32	4	31	4	31	4	31	4	31	4	31	4	31	4	30	4
Blackwater	132	CW	34	24	34	23	34	23	33	23	33	23	32	22	33	22	32	22	32	22	32	22
Blackwater	66	CW	102	14	100	14	101	14	98	14	102	14	104	15	104	15	103	15	103	15	105	15
Bowen North	66	R	23	8	24	8	24	8	30	10	33	11	32	11	32	11	32	11	32	11	32	11
Bulli Creek (Waggamba)	132	B	21	11	21	11	21	11	21	10	21	10	21	10	21	10	21	10	21	10	21	10
Cairns	22	FN	45	6	44	6	45	6	43	5	43	5	43	5	43	5	42	5	42	5	42	5
Cairns City	132	FN	52	29	51	28	52	29	50	28	50	28	50	27	50	27	49	27	49	27	49	27
Calliope River	132	G	40	20	46	23	46	23	42	21	43	21	42	21	42	21	42	21	41	21	41	21
Cardwell	22	R	5	3	5	3	5	3	4	3	4	3	4	3	4	3	4	3	4	3	4	3
Chinchilla	132	SW	20	5	19	5	20	5	19	5	19	5	19	5	19	5	19	5	19	5	19	5
Clare South	66	R	66	18	65	18	66	18	64	17	65	18	64	17	64	17	64	17	64	17	64	17
Collinsville	33	N	16	7	15	7	16	7	15	7	15	7	15	7	15	7	15	6	15	6	15	6
Columboola	132	SW	112	27	111	27	112	27	109	26	110	27	108	26	108	26	107	26	107	26	106	26
Dan Gleeson	66	R	90	50	90	50	91	50	89	49	91	50	90	49	84	43	84	42	84	42	84	43
Dysart	66	CW	49	8	49	8	49	8	48	8	48	8	47	8	47	8	47	8	46	8	46	8
Edmonton	22	FN	33	6	33	6	33	6	32	6	32	6	32	6	32	6	31	6	31	6	31	6
Egans Hill	66	CW	73	15	73	15	74	16	72	15	73	15	73	15	73	15	73	15	73	15	74	15
El Arish	22	FN	4	1	4	0	4	1	4	0	4	0	4	0	4	0	4	0	4	0	4	0
Garbutt	66	R	75	41	75	41	76	42	74	41	75	41	74	41	69	35	69	35	69	35	70	35

Table A.2 Ergon connection point forecast of winter native maximum demand *(continued)*

Connection point	Voltage (kV)	Zone	2017		2018		2019		2020		2021		2022		2023		2024		2025		2026	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Gin Gin	132	WB	118	16	117	16	117	16	114	15	115	15	113	15	113	15	112	15	111	15	111	15
Gladstone South	66	G	58	19	58	19	59	19	59	20	60	20	59	20	60	20	60	20	60	20	60	20
Ingham	66	R	38	7	38	7	38	7	37	6	37	6	37	6	37	6	36	6	36	6	36	6
Innisfail	22	FN	22	11	22	11	22	11	22	11	22	11	21	11	21	11	21	11	21	11	21	10
Kamerunga	22	FN	47	14	47	14	47	14	46	14	46	14	45	13	45	13	45	13	44	13	44	13
Lilyvale (Barcaldine & Clermont)	132	CW	30	2	30	2	30	2	29	2	30	2	29	2	29	2	29	2	29	2	29	2
Lilyvale	66	CW	142	60	140	59	143	60	146	61	147	62	155	65	155	65	153	64	152	64	152	64
Mackay	33	N	71	42	70	42	71	43	69	42	70	42	70	42	70	42	70	42	70	42	70	42
Middle Ridge	110	SW	261	24	259	23	261	24	255	23	257	23	253	23	254	23	252	23	252	23	251	23
Middle Ridge (Postmans Ridge)	110	M	11	4	11	4	12	4	11	4	12	4	11	4	12	4	12	4	12	4	12	4
Moranbah (Broadlea)	132	N	46	15	46	15	46	15	45	15	45	15	47	15	50	16	49	16	49	16	49	16
Moranbah	66 and 11	N	104	30	119	34	119	34	116	33	116	33	134	39	154	44	152	44	151	44	151	43
Moura	66	CW	60	19	59	19	60	19	58	18	59	18	58	18	59	18	58	18	58	18	58	18
Nebo	11	N	3	1	3	1	3	1	3	1	3	1	3	1	3	1	3	1	3	1	3	1
Newlands	66	N	35	13	35	13	37	14	39	15	39	15	39	15	39	15	38	15	38	15	38	15
Oakey	110	SW	21	4	21	4	21	4	20	4	20	4	20	4	20	4	20	4	20	4	19	4
Pandoin	66	CW	38	8	37	8	38	8	37	8	38	8	37	8	38	8	38	8	38	8	38	8
Pioneer Valley	66	N	54	22	54	22	54	23	53	22	54	22	53	22	53	22	53	22	53	22	53	22

Table A.2 Ergon connection point forecast of winter native maximum demand *(continued)*

Connection point	Voltage (kV)	Zone	2017		2018		2019		2020		2021		2022		2023		2024		2025		2026	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Proserpine	66	N	49	18	48	18	49	18	47	18	48	18	47	18	48	18	47	17	47	17	47	17
Rockhampton	66	CW	90	19	89	19	89	19	86	18	87	18	85	18	85	18	84	18	84	17	83	17
Ross (Kidston, Milchester and Georgetown)	132	R	61	20	61	20	62	20	60	20	61	20	61	20	61	20	61	20	61	20	61	20
Stony Creek	132	N	6	3	6	3	6	3	6	3	6	3	6	3	6	3	6	3	6	3	6	3
Tangkam	110	SW	85	21	84	21	85	21	83	21	84	21	83	21	83	21	82	20	81	20	81	20
Tarong	66	SW	42	13	41	13	41	13	40	13	40	13	40	12	40	12	39	12	39	12	39	12
Teebar Creek (Isis and Maryborough)	132	WB	99	13	98	13	99	13	96	12	97	13	95	12	95	12	95	12	94	12	94	12
Townsville East	66	R	34	19	34	19	35	19	34	19	34	19	34	19	32	16	32	16	32	16	32	16
Townsville South	66	R	65	36	64	35	63	35	61	34	61	33	59	33	55	28	54	27	53	27	52	27
Tully	22	R	12	5	12	5	12	5	11	5	11	5	11	5	11	5	11	5	11	5	11	5
Turkinje (Craiglie and Lakeland)	132	FN	19	6	19	6	19	6	19	6	19	6	18	6	18	6	18	6	18	6	18	6
Turkinje	66	FN	59	13	63	14	63	14	64	15	71	16	70	16	70	16	69	16	69	16	69	16
Woolooga (Kilkivan)	132	WB	23	4	23	4	23	4	22	4	22	4	22	4	22	4	22	4	22	4	22	4
Woree (Cairns North)	132	FN	39	7	40	7	42	8	42	8	44	8	44	8	46	8	47	8	48	9	49	9
Yarwun (Boat Creek)	132	G	43	23	43	22	43	22	42	22	43	23	44	23	44	23	43	23	43	23	43	22
Hail Creek and King Creek	Various	N	44	9	43	9	44	9	42	9	43	9	42	9	42	9	42	8	41	8	41	8

Table A.3 Energex connection point forecast of summer native maximum demand

Connection point	Voltage (kV)	Zone	2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25		2025/26		2026/27	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Abermain	110	M	58	20	58	20	58	20	58	20	59	20	59	20	59	20	59	20	58	20	58	20
Abermain	33	M	93	15	94	15	97	16	98	16	99	16	100	16	102	16	103	18	104	18	105	19
Algester	33	M	66	16	66	16	65	16	65	16	65	16	65	16	65	16	64	16	63	16	63	16
Ashgrove West	110	M	130	14	130	14	130	14	131	14	131	14	131	14	131	14	131	14	130	14	130	14
Ashgrove West	33	M	73	6	73	6	73	6	73	6	73	6	74	6	74	6	75	6	75	6	76	6
Belmont	110	M	425	257	425	256	426	257	436	263	439	265	444	268	446	269	445	269	434	262	434	262
Blackstone (Raceview)	110	M	92	13	94	13	95	13	95	13	95	14	96	14	96	14	96	14	96	14	97	14
Bundamba	110	M	36	23	36	23	36	23	36	23	37	23	37	23	37	23	37	23	37	23	37	23
Goodna	33	M	108	13	109	13	113	13	115	13	117	14	119	14	121	14	123	14	124	15	126	15
Loganlea	110	M	285	116	283	116	282	115	285	117	289	118	291	119	292	119	292	119	290	119	289	118
Loganlea	33	M	90	16	90	16	90	16	90	16	90	16	90	16	90	16	90	16	90	16	91	16
Middle Ridge (Postmans Ridge and Gatton)	110	M	112	15	112	15	112	15	113	15	113	15	114	15	114	15	114	15	114	15	114	15
Molendinar	110	GC	413	52	414	52	416	52	420	53	423	53	425	53	428	54	429	54	428	54	430	54
Mudgeeraba	110	GC	341	91	339	90	340	90	340	90	342	91	344	91	346	92	348	93	350	93	352	94
Mudgeeraba	33	GC	19	7	19	7	19	7	19	7	19	7	19	7	19	7	19	7	19	7	18	7
Murarrie	110	M	415	94	421	95	427	96	429	97	431	97	431	97	437	98	451	102	461	104	475	118
Palmwoods	110 & 132	M	361	176	361	176	363	177	367	179	375	183	380	185	386	188	387	189	389	190	391	190
Redbank Plains	11	M	23	8	23	8	24	8	24	8	25	8	25	8	26	9	26	9	27	9	27	9
Richlands	33	M	125	34	125	34	125	34	125	34	125	34	125	34	125	34	124	34	123	34	123	34
Rocklea	110	M	159	65	159	64	160	65	160	65	161	65	162	66	162	66	168	69	185	76	185	75

Table A.3 Energex connection point forecast of summer native maximum demand *(continued)*

Connection point	Voltage (kV)	Zone	2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25		2025/26		2026/27	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Runcorn	33	M	50	7	50	7	50	7	50	7	50	7	50	7	50	7	49	7	49	7	49	7
South Pine	110	M	882	180	878	180	881	180	883	181	891	182	895	183	899	184	899	184	898	184	900	184
Sumner	110	M	34	16	34	16	33	16	33	15	33	15	33	15	33	15	33	15	32	15	32	15
Tennyson	33	M	168	27	171	28	176	29	176	29	178	29	175	29	172	28	174	28	175	29	176	29
Wecker Road	33	M	133	23	133	23	133	23	133	23	133	23	133	23	133	23	133	23	132	23	132	23
Woolooga (Gympie)	132	M	180	23	179	23	180	23	180	23	181	23	182	23	183	23	184	24	185	24	186	24

Table A.4 Energex connection point forecast of winter native maximum demand

Connection point	Voltage (kV)	Zone	2017		2018		2019		2020		2021		2022		2023		2024		2025		2026	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Abermain	110	M	51	20	52	21	52	21	52	21	52	21	53	21	53	21	53	21	53	21	53	21
Abermain	33	M	69	6	71	6	72	6	75	6	76	6	78	6	79	6	81	7	83	7	84	7
Algester	33	M	58	30	59	31	59	31	58	30	58	30	58	30	58	30	58	30	58	30	58	30
Ashgrove West	110	M	135	13	137	13	137	13	136	13	137	13	138	13	138	13	139	13	141	13	141	13
Ashgrove West	33	M	58	7	59	7	59	7	58	7	59	7	59	7	60	7	61	7	62	7	62	7
Belmont	110	M	319	53	323	54	323	54	322	54	331	55	332	56	336	56	340	57	343	57	338	57
Blackstone (Raceview)	110	M	66	13	67	13	70	14	70	14	70	14	71	14	71	14	72	14	73	14	74	15
Bundamba	110	M	31	17	31	17	31	17	31	17	31	17	31	17	31	17	31	17	32	18	32	18
Goodna	33	M	85	7	89	8	92	8	93	8	95	8	97	8	100	9	103	9	105	9	107	9
Loganlea	110	M	289	85	291	86	290	86	289	85	295	87	297	88	299	88	303	89	305	90	307	91
Loganlea	33	M	78	11	79	11	79	11	78	11	79	11	79	11	79	11	80	12	81	12	81	12
Middle Ridge (Postmans Ridge and Gatton)	110	M	48	6	48	6	48	6	48	6	49	6	49	6	49	6	49	6	50	6	50	6
Molendinar	110	GC	371	27	375	28	379	28	379	28	382	28	384	28	387	28	392	29	398	29	402	29
Mudgeeraba	110	GC	245	68	249	69	248	69	246	69	249	69	250	70	251	70	255	71	259	72	263	73
Mudgeeraba	33	GC	19	6	19	6	19	6	19	6	19	6	19	6	19	6	19	6	19	6	19	6
Murarrie	110	M	323	70	330	71	334	72	338	73	341	74	344	74	349	75	355	77	367	79	377	81
Palmwoods	110 & 132	M	333	132	337	134	337	134	339	135	343	136	350	139	356	142	364	145	368	146	375	149
Redbank Plains	11	M	17	4	17	4	18	4	18	4	18	4	19	4	19	4	20	5	20	5	21	5

Table A.4 Energex connection point forecast of winter native maximum demand *(continued)*

Connection point	Voltage (kV)	Zone	2017		2018		2019		2020		2021		2022		2023		2024		2025		2026	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Richlands	33	M	77	13	78	13	77	13	77	13	77	13	77	13	77	13	78	13	78	13	79	13
Rocklea	110	M	157	40	155	39	154	39	154	39	156	40	157	40	158	40	159	40	168	43	188	48
Runcorn	33	M	47	9	50	9	50	9	49	9	49	9	49	9	49	9	50	9	50	9	50	9
South Pine	110	M	707	96	715	98	714	97	711	97	718	98	723	99	727	99	734	100	741	101	748	102
Sumner	110	M	24	8	24	8	24	8	24	7	24	7	24	7	24	7	24	7	24	7	24	7
Tennyson	33	M	134	13	136	13	140	13	143	14	144	14	145	14	143	14	141	14	144	14	147	14
Wecker Road	33	M	100	10	101	10	101	10	100	10	101	10	101	10	101	10	102	10	103	10	104	10
Woolooga (Gympie)	132	M	184	10	187	10	187	10	186	10	188	10	189	10	190	10	193	11	195	11	198	11

Table A.5 Sum of individual summer native peak forecast demands for the transmission connected loads

Connection point (1)	2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25		2025/26		2026/27	
	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Transmission connected industrial loads (2)	1,130	366	1,130	366	1,130	366	1,130	366	1,130	366	1,130	366	1,130	366	1,130	366	1,130	366	1,130	366
Transmission connected mining loads (3)	67	26	68	26	70	27	72	27	76	29	101	37	103	38	104	38	104	38	104	38
Transmission connected CSG loads (4)	797	262	819	269	820	269	811	267	831	273	832	274	824	271	814	267	783	257	754	248
Transmission connected rail supply substations (5)(6)	257	-255	257	-255	257	-255	257	-255	257	-255	257	-255	257	-255	257	-255	257	-255	257	-255

Notes:

(1) Transmission connected customers supply 10-year active power (MW) forecasts. The reactive power (MVAr) forecasts are calculated based on historical power factors at each connection point. The new CSG connection points have been assigned a power factor based on customer agreement of 0.95 power factor (or better) for 132kV and 0.96 power factor (or better) for 275kV connection point voltage.

(2) Industrial loads include:

- Ross zone – Townsville Nickel, Sun Metals and Invicta Mill
- Gladstone zone – RTA, QAL and BSL.

(3) Mining loads include:

- North zone – Burton Downs, North Goonyella, Goonyella Riverside and Eagle Downs.

(4) CSG loads include:

- Bulli zone – Kumbarilla Park
- Surat zone – Wandoan South, Orana and Columboola.

(5) Rail supply substations include:

- North zone – Mackay Ports, Oonooie, Bolingbroke, Wandoo, Mindi, Coppabella, Wotonga, Peak Downs and Mt McLaren
- Central West zone – Norwich Park, Gregory, Blackwater, Bluff, Wycarbah, Duaringa, Grantleigh and Raglan
- Gladstone zone – Callemondah.

(6) There are a number of connection points that supply the Aurizon rail network and these individual connection point peaks have been summated. Due to the load diversity between the connection points, the real and reactive power (MW and MVAr) coincident peak is significantly lower.

Table A.6 Sum of individual winter native peak forecast demands for the transmission connected loads

Connection point (1)	2016		2017		2018		2019		2020		2021		2022		2023		2024		2025	
	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Transmission connected industrial loads (2)	1,135	371	1,135	371	1,135	371	1,135	371	1,135	371	1,135	371	1,135	371	1,135	371	1,135	371	1,135	371
Transmission connected mining loads (3)	65	25	67	25	69	26	70	26	75	28	99	36	100	36	100	36	100	36	100	36
Transmission connected CSG loads (4)	770	253	815	268	828	272	812	267	830	273	842	277	834	274	812	267	801	263	762	250
Transmission connected rail supply substations (5)(6)	257	-255	257	-255	257	-255	257	-255	257	-255	257	-255	257	-255	257	-255	257	-255	257	-255

Notes:

(1) Transmission connected customers supply 10-year active power (MW) forecasts. The reactive power (MVAr) forecasts are calculated based on historical power factors at each connection point. The new CSG connection points have been assigned a power factor based on customer agreement of 0.95 power factor (or better) for 132kVand 0.96 power factor (or better) for 275kV connection point voltage.

(2) Industrial loads include:

- Ross zone – Townsville Nickel, Sun Metals and Invicta Mill
- Gladstone zone – RTA, QAL and BSL.

(3) Mining loads include:

- North zone – Burton Downs, North Goonyella, Goonyella Riverside and Eagle Downs.

(4) CSG loads include:

- Bulli zone – Kumbarilla Park
- Surat zone – Wandoan South, Orana and Columboola.

(5) Rail supply substations include:

- North zone – Mackay Ports, Oonooie, Bolingbroke, Wandoo, Mindi, Coppabella, Wotonga, Peak Downs and Mt McLaren
- Central West zone – Norwich Park, Gregory, Blackwater, Bluff, Wycarbah, Duaringa, Grantleigh and Raglan
- Gladstone zone – Callemondah.

(6) There are a number of connection points that supply the Aurizon rail network and these individual connection point peaks have been summated. Due to the load diversity between the connection points, the real and reactive power (MW and MVAr) coincident peak is significantly lower.

Appendix B – Powerlink's forecasting methodology

A discussion of Powerlink's forecasting methodology is presented below. Powerlink is publishing its forecasting model with the 2017 TAPR (Transmission Annual Planning Report) which should be reviewed in conjunction with this description.

Powerlink's forecasting methodology for energy, summer maximum demand and winter maximum demand comprises the following three steps:

1. Transmission customer forecasts

   The loads of customers other than Energex and Ergon that connect directly to Powerlink's transmission network are assessed based on their forecasts, recent history and through direct consultation. Only committed load is included in the medium economic outlook forecast while some speculative load is included in the high economic outlook forecast.

2. Econometric regressions

   Forecasts are developed for Energex and Ergon based on relationships between past usage patterns and economic variables where reliable forecasts for these variables exist.

3. New technologies

   The impact of new technologies such as rooftop solar PV, distribution connected PV solar farms, battery storage, electric vehicles and demand side management (DSM) are factored into the forecasts for Energex and Ergon.

The discussion below provides further insight to steps 2 and 3, where DNSP (Distribution Network Service Provider) forecasts are developed.

Econometric regressions

DNSP forecasts are prepared for summer maximum demand, winter maximum demand and annual energy.

To prepare these forecasts, regression analysis is carried out using native demand and energy plus distribution connected solar photovoltaic (PV) which includes rooftop PV and distribution connected solar PV farms as this represents the total underlying Queensland DNSP load. This approach is necessary as the regression process needs to describe all electrical demand in Queensland, irrespective of the type or location of generation that supplies it.

Data Preparation

The first step in the regression analysis is to assemble historical native energy and maximum demand values as follows:

- Energy

  Determine DNSP native energy for each year from 2000/01. As this work is done in March, an estimation is prepared for the current financial year which will be updated with actual totals 12 months later when preparing the next TAPR.

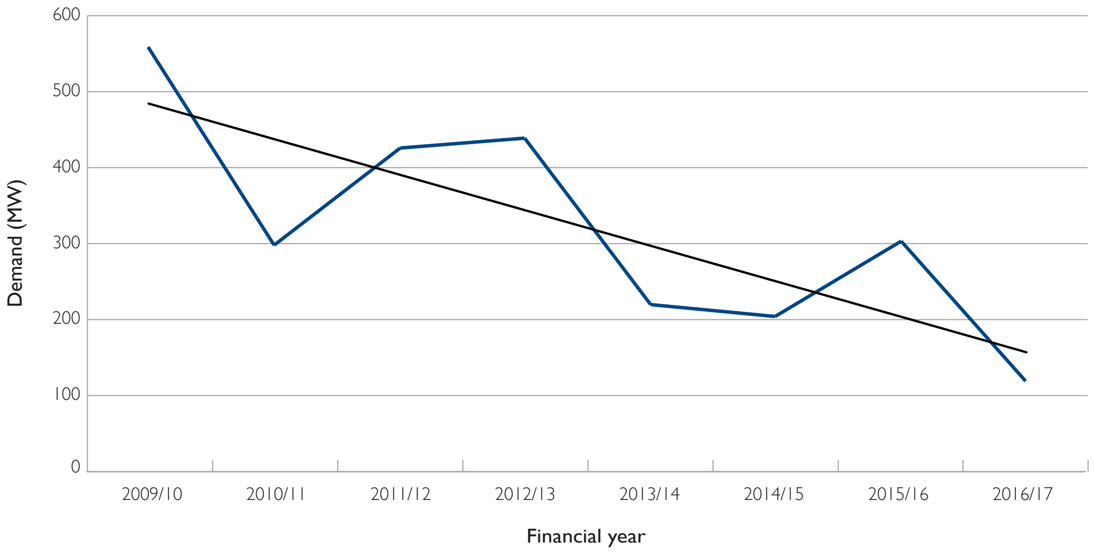
- Winter maximum demand

  The DNSP native demand at the time of winter state peak is collated for each year from winter 2000. Each of these demands are then normalised to average weather conditions (50% probability of exceedance (PoE)). Powerlink's method for weather correction is described later in this appendix.

- Summer maximum demand

  The DNSP native demand at the time of summer state peak is collated for each year from summer 2000/01. Each of these demands are then normalised to average weather conditions (50% PoE). DNSP native demand at the time of summer state evening peak (after 6pm) is also collated for each year from summer 2000/01. These demands are also corrected to average weather conditions. This evening series is used as the basis for regressing as evidence supports Queensland moving to a summer evening peak due to the increasing impact of distribution connected solar PV. This move to an evening peak by 2020/21 is supported through analysis of day and evening trends for corrected maximum demand as illustrated in Figure B.1.

Figure B.1 Difference in summer day and summer evening normalised maximum demand



Before the energy data can be used in a regression, it is necessary to make appropriate adjustments to account for distribution connected solar PV. This ensures that the full underlying DNSP load is being regressed. This energy adjustment assumes that rooftop solar PV, on average, has a 13% capacity factor. This 13% figure is based on observations through the Australian PV Institute.

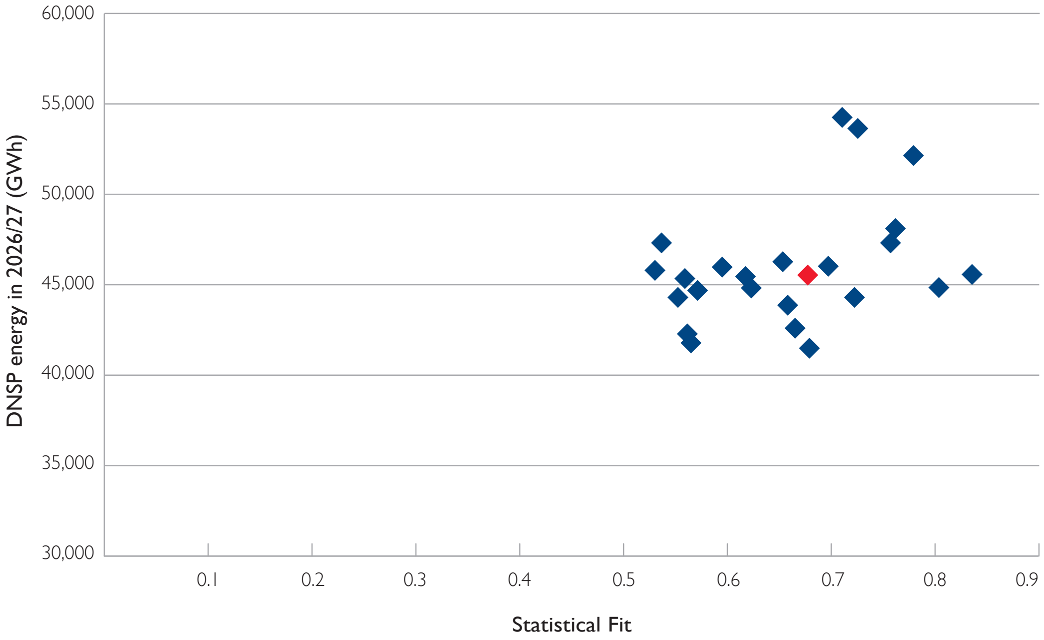
Following the regression for energy, the forecast is then adjusted to take into account future distribution connected solar PV contributions based on forecast distribution connected solar PV capacity. Forecast summer maximum demand is now based on an evening regression adjusted for the transition to an evening peak. Winter maximum demand has historically occurred in the evening, so no PV adjustment needs to be applied to the winter maximum demand forecast.

Energy regression

An energy regression is developed using historical energy data (described above) as the output variable and a price and economic variable for inputs. A logarithmic relationship between the input and output variables is used in keeping with statistical good practice.

Input variables are selected from two price variables (supplied by the Australian Energy Market Operator) and 16 economic variables (supplied by Deloitte Access Economics). This provides 32 combinations. For each of these 32 combinations the option of a one year delay to either or both input variables is also considered leading to a total of 128 regressions being assessed. Of these, the top 25 are selected and placed on a scatter plot as shown in Figure B.2 where the statistical fit and energy forecast at the end of the forecast period are assessed. The statistical fit combines several measures including R-squared, Durbin-Watson test for autocorrelation, mean absolute percentage error and mean bias percentage. All top 25 regressions shown in Figure B.2 qualify as statistically good regressions.

Figure B.2 Energy regression results



The selected regression shown above in red uses Queensland retail turnover with no delay and total electricity price with a one year delay. Within the population of statistically good regressions, the selected regression reflects a central outcome at the end of the regression period, uses broad based input variables and uses the same variables as used in the 2016 TAPR.

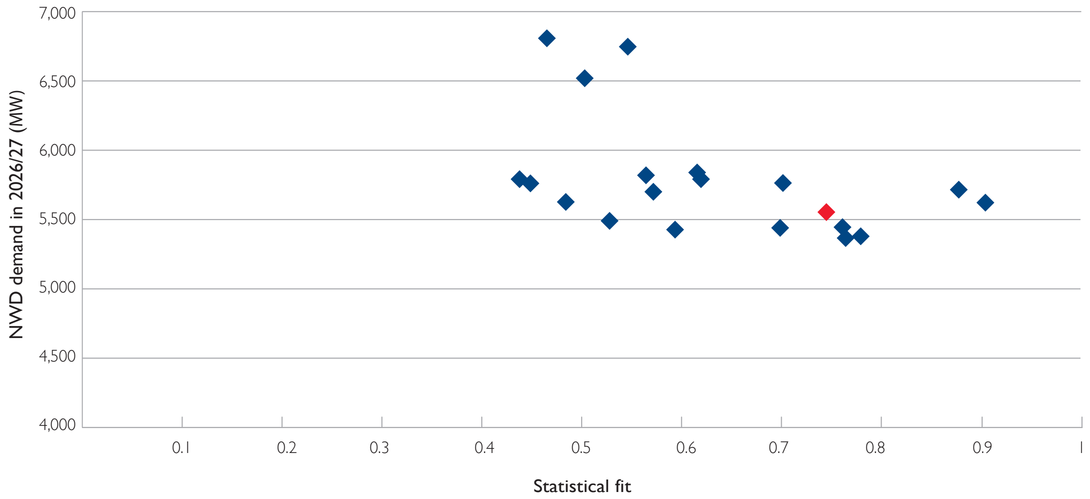
The regression is carried out using medium data leading to the medium economic forecast. High and low energy forecasts are then determined by applying the appropriate forecast economic data to the model.

Summer and winter maximum demand regressions

Maximum demand forecasts are based on two regressions. The temperature-normalised historical demands are split into two components: non-weather dependent (NWD) demand and weather dependent (WD) demand. NWD demand is determined as the median weekday maximum demand in the month of September. This reflects the low point in cooling and heating requirements for Queensland. The balance is the WD demand. For summer, this is the difference between the corrected summer maximum demand and the NWD demand based on the previous September. For winter, this is the difference between the corrected winter maximum demand and the NWD demand based on the following September.

The forecast NWD demand is therefore used for both the summer and winter maximum demand forecasts. The regression process used to determine the NWD demand is the same as used for energy with the results illustrated in Figure B.3.

Figure B.3 Non-weather dependent demand regression results

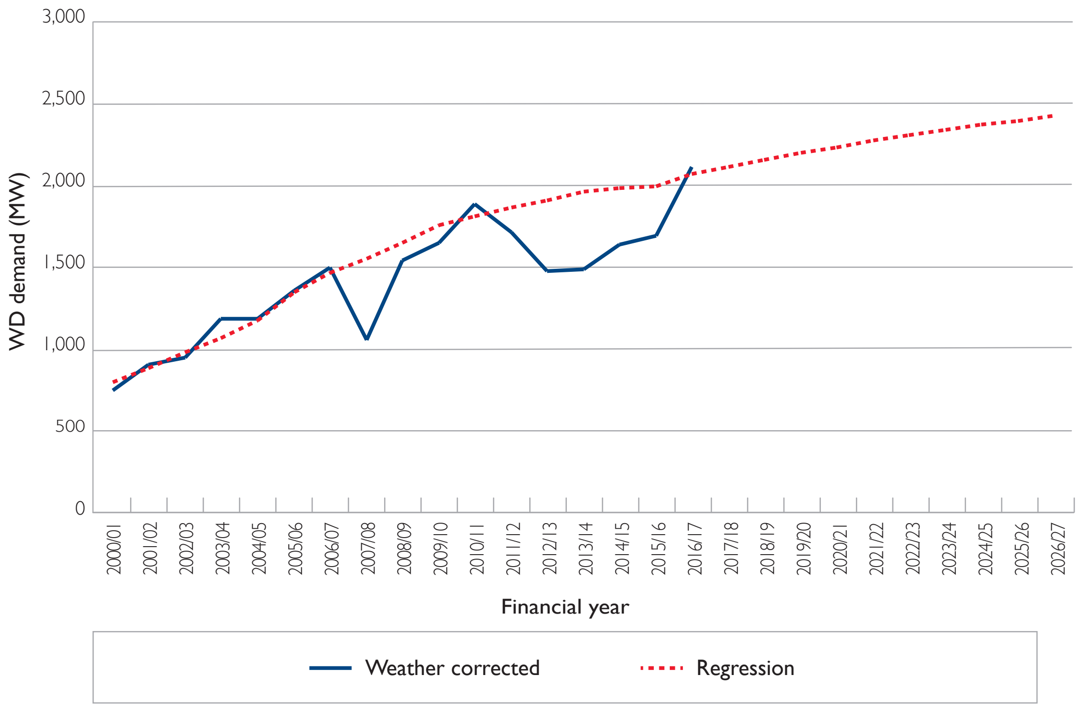


The selected regression shown above in red uses Queensland retail turnover and total electricity price, both with a one year delay. These are the same variables used in the 2016 TAPR.

The summer and winter WD demand is mainly a reflection of air conditioning usage. These regressions have been based on one input variable – population multiplied by Queensland air conditioning penetration. Historical and forecast air conditioning penetration rates are provided annually in the Queensland Household Energy Survey.

The 2016/17 summer WD demand (QHES) was a record peak and was substantially higher than the previous four summers. A number of troughs for the summer WD demand have been recorded, these include summer 2007/08 and the period from 2011/12 to 2015/16. Summer 2007/08 aligns with the initial shock of the Global Financial Crisis (GFC) and the period from 2011/12 to 2015/16 aligns with increases in electricity prices from about 2009. The QHES results indicate that households were more frugal in their electricity behaviours from 2011 to 2015 and that this behaviour has been tempered in 2016. The summer WD demand regression is illustrated in Figure B.4, with the years impacted by the GFC and increased prices removed from the regression.

Figure B.4 Weather dependent demand regression – summer



Similar to the energy analysis, low, medium and high economic outlook forecasts are produced for maximum demands by applying the appropriate economic forecasts as inputs. For maximum demand it is also necessary to provide three seasonal variation forecasts for each of these economic outlooks leading to nine forecasts in total. These seasonal variations are referred to as 10% PoE, 50% PoE and 90% PoE forecasts. They represent conditions that would expect to be exceeded once in 10 years, five times in 10 years and nine times in 10 years respectively. If the WD analysis described above is applied to historical demands, temperature corrected to 50% PoE conditions, it leads to the 50% PoE forecast. The analysis is repeated using historical demands corrected to 10% PoE and 90% PoE conditions to produce forecasts for each condition.

New technologies

Understanding the future impacts of new technologies is crucial to developing robust and meaningful demand and energy forecasts. Recognising the importance that these technologies will play in shaping future demand and energy, Powerlink is committed to furthering its understanding of these drivers. The new technologies discussed in this section are not incorporated within the energy regression and the summer and winter maximum demand regressions. To include these new technologies, post regression adjustments are made to the DNSP demand and energy forecasts.

Each year, Powerlink hosts a Demand and Energy forum to seek input from industry experts and stakeholders regarding new technologies and the impacts that they may have on future electrical demand and electrical energy consumption. A summary of the 2017 Demand and Energy Forum is available on Powerlink's website. Based on the input and discussion at this forum, Powerlink has adopted technology and other inputs as summarised in Table B.1.

Table B.1 New Technology Assumptions

	Rooftop PV	Distribution connected PV solar farms	Battery storage	Electric vehicles	Tariff reform / DSM	Customer momentum
Energy (GWh) (1)	2,498	1,894	0	-355	0	1,455
Maximum demand (MW) (2)	0	0	175	0	150	237
Installed capacity in 2026/27 (MW)	3,800	940				
Installed capacity in 2026/27 (MWh)			790			
First year of impact	now	now	now	now	2020/21	2019/20

Notes:

(1) This is the energy reduction in financial year 2026/27 compared to 2016/17.

(2) This is the maximum demand reduction in summer 2026/27 compared to summer 2016/17.

Powerlink recognises there is considerable uncertainty regarding the impact of new technology and other inputs on the demand and energy forecasts. Due to these uncertainties Powerlink has provided this additional information to provide transparency and allow readers to substitute alternative assumptions into the forecast if desired.

Rooftop solar PV

The installed capacity of rooftop solar PV in Queensland as at the end of 2016 was approximately 1,700MW. After a rapid uptake in the years 2011 to 2013, installations have now moderated to a rate of around 15MW[1] per month, predominately residential. This baseline level of growth is expected to continue.

As battery storage systems fall in price it is expected that an additional 300MW of rooftop solar PV will connect by 2026/27. In total, this will increase capacity of rooftop solar PV in Queensland to 3,800MW by 2026/27.

Analysis has revealed that Queensland will move to a summer evening peak by 2020/21 and so further rooftop solar PV which is predominantly installed facing north is expected to have little impact on maximum demand after this time. Energy impacts have been based on an average output of 13%[1] capacity.

Powerlink is a member of the Australian PV Institute which supplies real time data for rooftop solar PV. This information allows Powerlink to analyse a range of PV effects and in particular its impact on maximum demand.

Future impacts of rooftop solar PV will need to be monitored carefully. As older systems fail, they may be replaced with larger systems or not replaced at all. Furthermore, if enabling factors such as government incentives or rapid uptake of battery storage were to occur, then future rooftop solar PV installation levels could increase beyond this forecast.

Distribution connected solar PV farms

State and Federal Government initiatives are driving future renewable capacity in Queensland predominately in the form of solar PV farms. Solar PV farms connecting directly to the distribution network will reduce the amount of energy being delivered through the transmission network and accelerate the delay of the state peak from around 5:30pm to an evening peak. The 2016 TAPR did not separate rooftop solar PV and distribution connected solar PV farms. Current initiatives are expected to result in approximately 490MW of PV solar farms connecting to the distribution network by 2020.

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[1] Based on information obtained from the Australian PV Institute

Future VRE initiatives by State and Federal Government to support Australia's commitment to the Paris Accord are expected to drive increases in distribution connected PV solar farms from 2023.

Battery storage

Battery storage technology has the potential to significantly change electricity consumption patterns. In particular, this technology could "flatten" electricity usage and thereby reduce the need to develop transmission services to cover short duration peaks. By coupling this technology with rooftop solar PV, consumers may have the option to go "off grid". A number of factors will drive the uptake of this technology, namely:

- affordability
- introduction of time of use tariffs
- continued uptake of rooftop solar PV generation
- practical issues such as space, aesthetics and safety
- whether economies of scale favour a particular level of aggregation.

The 2016 QHES indicates that around 8% of Queensland households are considering the purchase of a battery storage system. However the same survey indicates that most people underestimate the current price of installing a storage solution. For the 2017 TAPR, Powerlink developed a new methodology to estimate the uptake of battery storage and the impact on summer maximum demand. The methodology involves the following steps:

- Estimate the maximum population of residential battery storage systems, based on dwelling type, home ownership, and household income factors. This is estimated to be 400,000 households with batteries.
- Bell curved the uptake of battery storage systems based on the financial payback period, with a mean of five years and a standard deviation of 1.75 years.
- Calculate the pay-back period for a market leading battery storage system for each year in the 10-year outlook period. The installation price of future battery storage systems was estimated using CSIRO's battery cost path from their electricity network transformation roadmap interim program report.
- From the bell curve of battery uptake (based on the financial payback period) and the calculated yearly payback period of a battery system, calculate the uptake of battery storage systems. Multiply the yearly uptake by the predicted average size of a battery storage system (10kWh), to calculate a predicted yearly uptake in MWh.
- Calculate the yearly maximum demand reduction by taking into account the maximum discharge rate of the fleet of battery storage systems (a MW figure equivalent to 37% of the energy storage capacity) and the proportion of systems that are expected to be discharging at the time of summer maximum demand (assumed to be 60%).

Electric vehicles

The uptake of electric vehicles in Australia is quite low compared to world leading countries such as Norway and the Netherlands. Without government policy support for the adoption of electric vehicles, uptake is expected to be limited in the short-term. The expected reduction in battery costs will likely lift electric vehicle sales in the medium to long-term.

Powerlink has adopted the neutral uptake scenario from the Electric Vehicle Insights paper[2] prepared in August 2016 by Energeia for AEMO.

It is estimated that a 1% penetration of electric vehicles on the road would result in approximately 0.2% increase in total energy usage.

It is expected that most owners will charge their electric vehicles during off peak periods, resulting in minimal increase in maximum demand. Therefore, Powerlink has not included a specific adjustment for electric vehicles in its maximum demand forecast.

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[2] Available on AEMO's website, at www.aemo.com.au

Tariff reform and demand side management

Network tariff reforms could influence consumer behaviour, shifting energy usage away from peak times. In addition to this maximum demand reduction, it is anticipated that network tariff reforms could also influence future use of battery storage technology, encouraging consumers to draw from batteries during maximum demand / high price times. The extent to which this occurs will depend on how quickly new tariffs are offered, the tariff structure and the adoption rate.

"In Australia and internationally there is evidence that customers will significantly reduce their demand in response to well-designed price signals that reward off-peak use and peak demand management. Sixty percent of trials internationally have resulted in peak reductions of 10 per cent or more."[3]

A big challenge to tariff reform is gaining consumer acceptance. Many consumers dislike complicated tariffs and any move to remove existing tariff cross subsidies could meet with resistance. Some of this peak reduction is already captured through the battery storage allowance described above.
An additional 150MW has been assumed within this forecast and represents a further 2% reduction in the total maximum demand from the Energex and Ergon networks. As tariff reform is likely to result in load shifting, the impact on energy consumption is expected to be negligible.

Customer momentum factor

Over the last 10 years, many customers have been purchasing appliances with higher energy efficiency ratings and adopting more energy efficient behaviours in an effort to minimise financial impacts. The electricity price metric used in the regression model is forecast to increase by a further 16% over the next 10 years. The logic hardwired within the regression model suggests that customers will change their behaviour in response to moderating electricity prices.

To allow for this effect, a customer momentum factor has been developed and is explicitly incorporated within the energy and non-weather dependent demand regressions. The impact of price on electricity usage is determined for the last 10 years. Rather than simply accepting the regression model's prediction for the next 10 years, a weighting of two thirds has been applied. This results in a dampening effect, limiting the 'bounce-back' in energy and demand with the moderation of electricity prices.

It is expected that this factor will be reduced or removed in future years as additional information on customers' actual behaviour during moderating electricity prices is captured in the data series.

Weather correction methodology

Maximum demand is strongly related to the temperature. To account for the natural variation in the weather from year to year, temperature correction is carried out to normalise raw demand observations. Three conditions are calculated:

- 10% PoE demand, corresponding to a one in 10-year season (i.e. a particularly hot summer or cold winter)
- 50% PoE demand, which indicates what the demand would have been if it was an 'average' season
- 90% PoE demand, corresponding to a nine in 10-year season (particularly mild weather).

Within each year, separate temperature corrections are calculated for extended summer and extended winter seasons. Summer is taken as November to March. Winter is taken as May to August.

Temperature correction is applied to historical metered load supplied to connection points with Ergon and Energex. Powerlink's other direct-connect customers are largely insensitive to temperature.

Powerlink's temperature correction process is described below:

- Develop composite temperature

  The temperature from multiple weather stations is combined to produce a composite temperature for all of Queensland. The weighting of each weather station is based on the amount of Energex and Ergon-supplied load in the vicinity of that weather station.

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[3] Towards a National Approach to Electricity Network Tariff Reform (page 6) – ENA Position Paper December 2014

- Exclude mild days and holidays

  To ensure that the fitted model accurately describes the relationship between temperature and maximum demand on days when demand is high, days with mild weather, and the two-week period around Christmas (when many businesses are closed) are excluded from the dataset.

- Calculate a regression model for each season since 2000

  A regression model is calculated for each summer since 2000/01 and winter since 2000, expressing the daily maximum demand as a function of: daily maximum temperature, daily minimum temperature, daily 6pm temperature, and whether the day is a weekday.

- For each season, determine the 10% and 50% PoE thresholds using 22 years of weather data

  The regression model calculated for each season is then applied to the daily weather data recorded since 1995. This effectively calculates what the maximum demand would have been on each day if the relationship between maximum demand and temperature described by the model had existed at the time. A Monte-Carlo approach is used to incorporate the standard error from each season's regression model. The maximum demand calculated for each of the 22 years is recorded in a list, and the 10th, 50th and 90th percentile of the list is calculated to determine the 10% PoE, 50% PoE and 90% PoE thresholds.

- Final Scaling to Avoid Bias: To ensure that temperature correction process does not introduce any upward or downward bias, for each summer since 2000/01 and winter since 2000, the ratio of the calculated 50% PoE threshold to the actual maximum demand is calculated. The calculated PoE thresholds are divided by the average of these ratios.

Applying this methodology, the 2016/17 summer was hotter than average. Therefore, the 50% PoE demand is 90MW lower than the observed maximum demand on 12 February. The 2016 winter was slightly warmer than average, resulting in an upwards adjustment of 26MW to the observed winter maximum demand.

Appendix C – Estimated network power flows

This appendix illustrates 18 sample power flows for the Queensland region for each summer and winter over three years from winter 2017 to summer 2019/20. Each sample shows possible power flows at the time of winter or summer region 50% probability of exceedance (PoE) medium economic outlook demand forecast outlined in Chapter 2, with a range of import and export conditions on the Queensland/New South Wales Interconnector (QNI) transmission line.

The dispatch assumed is broadly based on historical observed dispatch of generators.

Sample conditions[1] include:

Figure C.3	Winter 2017 Queensland maximum demand 300MW northerly QNI flow
Figure C.4	Winter 2017 Queensland maximum demand 0MW QNI flow
Figure C.5	Winter 2017 Queensland maximum demand 700MW southerly QNI flow
Figure C.6	Winter 2018 Queensland maximum demand 300MW northerly QNI flow
Figure C.7	Winter 2018 Queensland maximum demand 0MW QNI flow
Figure C.8	Winter 2018 Queensland maximum demand 700MW southerly QNI flow
Figure C.9	Winter 2019 Queensland maximum demand 300MW northerly QNI flow
Figure C.10	Winter 2019 Queensland maximum demand 0MW QNI flow
Figure C.11	Winter 2019 Queensland maximum demand 700MW southerly QNI flow
Figure C.12	Summer 2017/18 Queensland maximum demand 200MW northerly QNI flow
Figure C.13	Summer 2017/18 Queensland maximum demand 0MW QNI flow
Figure C.14	Summer 2017/18 Queensland maximum demand 400MW southerly QNI flow
Figure C.15	Summer 2018/19 Queensland maximum demand 200MW northerly QNI flow
Figure C.16	Summer 2018/19 Queensland maximum demand 0MW QNI flow
Figure C.17	Summer 2018/19 Queensland maximum demand 400MW southerly QNI flow
Figure C.18	Summer 2019/20 Queensland maximum demand 200MW northerly QNI flow
Figure C.19	Summer 2019/20 Queensland maximum demand 0MW QNI flow
Figure C.20	Summer 2019/20 Queensland maximum demand 400MW southerly QNI flow

The power flows reported in this appendix assume the open points at the Gladstone South end of Callide A to Gladstone South 132kV double circuit. These open points can be closed depending on system conditions.

Table C.1 provides a summary of the grid section flows for these sample power flows and the limiting conditions capable of setting the maximum transfer.

Table C.2 lists the 275kV transformer nameplate capacity and the maximum loading of the sample power flows.

Figures C.1 and C.2 provide the generation, load and grid section legends for the subsequent figures C.3 to C.20. The reported generation and load is the transmission sent out and transmission delivered defined in Figure 2.4

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[1] The transmission network diagrams shown in this appendix are high level representations only, used to indicate zones and grid sections.

Table C.1: Summary of figures C.3 to C.20 – illustrative power flows and limiting conditions

Grid section (1)	Illustrative power flows (MW) at time of Queensland region maximum demand (2) (3)						Limit due to (4)
	Winter 2017	Winter 2018	Winter 2019	Summer 2017/18	Summer 2018/19	Summer 2019/20	
Figure	C.3 / C.4 / C.5	C.6 / C.7 / C.8	C.9 / C.10 / C.11	C.12 / C.13 / C.14	C.15 / C.16 / C.17	C.18 / C.19 / C.20	
FNQ Ross into Chalumbin 275kV (2 circuits) Tully into Woree 132kV (1 circuit) Tully into El Arish 132kV (1 circuit)	161/161/161	111/111/111	111/111/111	284/284/284	233/233/233	233/233/233	V
CQ-NQ Bouldercombe into Nebo 275kV (1 circuit) Broadsound into Nebo 275kV (3 circuits) Dysart to Peak Downs 132kV (1 circuit) Dysart to Eagle Downs 132kV (1 circuit)	532/532/532	498/498/498	501/501/501	726/726/726	677/677/677	675/675/675	Th V
Gladstone Bouldercombe into Calliope River 275kV (1 circuit) Raglan into Larcom Creek 275kV (1 circuit) Calvale into Wurdong 275kV (1 circuit) Callide A into Gladstone South 132kV (2 circuits)	718/608/598	701/772/619	703/765/590	527/529/532	501/533/537	533/534/539	Th
CQ-SQ Wurdong into Gin Gin 275kV (1 circuit) Calliope River into Gin Gin 275kV (2 circuits) Calvale into Halys 275kV (2 circuits)	1,717/2,025/2,067	1,332/1,636/2,069	1,347/1,650/2,071	1,767/1,767/1,767	1,718/1,832/1,832	1,832/1,832/1,832	Tr V
Surat Western Downs to Columboola 275kV (1 circuit) Western Downs to Orana 275kV (1 circuit) Tarong into Chinchilla 132kV (2 circuits)	480/480/480	508/510/508	516/516/516	477/475/412	493/493/491	496/494/496	V
SWQ Western Downs to Halys 275kV (2 circuits) Braemar (East) to Halys 275kV (2 circuits) Millmerran to Middle Ridge 330kV (2 circuits)	1,182/891/920	1,149/857/513	981/764/515	1,984/1,981/2,001	1,360/1,271/1,261	1,271/1,269/1,255	(5)
Tarong Tarong to South Pine 275kV (1 circuit) Tarong to Mt England 275kV (2 circuits) Tarong to Blackwall 275kV (2 circuits) Middle Ridge to Greenbank 275kV (2 circuits)	3,277/3,123/3,162	3,064/2,935/2,778	3,064/2,931/2,772	4,032/4,031/4,062	3,659/3,613/3,643	3,603/3,603/3,632	V

Table C.1: Summary of figures C.3 to C.20 – illustrative power flows and limiting conditions *(continued)*

Grid section (1)	Illustrative power flows (MW) at time of Queensland region maximum demand (2) (3)						Limit due to (4)
	Winter 2017	Winter 2018	Winter 2019	Summer 2017/18	Summer 2018/19	Summer 2019/20	
Figure	C.3 / C.4 / C.5	C.6 / C.7 / C.8	C.9 / C.10 / C.11	C.12 / C.13 / C.14	C.15 / C.16 / C.17	C.18 / C.19 / C.20	
Gold Coast Greenbank into Mudgeeraba 275kV (2 circuits) Greenbank into Molendinar 275kV (2 circuits) Coomera into Cades County 110kV (1 circuit)	691/691/754	687/687/749	684/684/747	793/793/824	783/783/814	780/780/812	V

Notes:

(1) The grid sections defined are as illustrated in Figure C.2. X into Y – the MW flow between X and Y measured at the Y end; X to Y – the MW flow between X and Y measured at the X end.

(2) Grid power flows are derived from the assumed generation dispatch cases shown in figures C.3 to C.20. The flows estimated for system normal operation are based on the existing network configurations and committed projects. Power flow across each grid section can be higher at times of local zone peak.

(3) All grid section power flows shown are within network capability.

(4) Tr = Transient stability limit, V = Voltage stability limit and Th = Thermal plant rating.

(5) As stated in Section 5.5.6, SWQ grid section is not expected to impose limitations to power transfer under intact system conditions with the existing levels of generating capacity.

Table C.2: Capacity and sample loadings of Powerlink owned 275kV transformers

275kV substation (1)(2)(3)(4) (Number of transformers x MVA nameplate rating)	Zone (5)	Possible MVA loading at Queensland region peak (6)(7)(8)						Dependence other than local load	
		Winter 2017	Winter 2018	Winter 2019	Summer 2017/18	Summer 2018/19	Summer 2019/20	Significant dependence on	Minor dependence on
Chalumbin 275/132kV (2x200MVA)	FN	17	20	20	34	33	34	Kareeya generation	
Woree 275/132kV (2x375MVA)	FN	117	125	127	206	218	214	Barron Gorge generation	Kareeya and Ross zone generation
Ross 275/132kV (3x250MVA)	R	133	130	124	218	210	214	Ross zone generation	Hamilton Solar Farm, Whitsunday Solar Farm and Collinsville Solar Farm
Nebo 275/132kV (1x200MVA, 1x250MVA and 1x375MVA)	N	275	275	276	293	289	286	Mackay GT generation	Hamilton Solar Farm, Whitsunday Solar Farm and Collinsville Solar Farm
Strathmore 275/132kV (1x375MVA)	N	120	119	121	160	156	156	Invicta and Clare South SF, Hamilton SF, Whitsundays SF, Collinsville SF generation	Ross zone generation
Bouldercombe 275/132kV (1x200MVA and 1x375MVA)	CW	135	132	132	161	159	159		
Calvale 275/132kV (1x250MVA)	CW	131	133	142	149	158	135	Callide, Yarwun and Gladstone generation and 132kV network configuration	
Lilyvale 275/132kV (2x375MVA)	CW	171	171	164	210	200	221	Barcaldine generation	CQ-NQ flow
Larcom Creek 275/132kV (2x375MVA)	G	73	70	76	74	61	73	Yarwun generation	
Gin Gin 275/132kV (2x250MVA)	WB	150	147	158	150	158	157		CQ-SQ flow
Teebar Creek 275/132kV (2x375MVA)	WB	74	77	77	69	76	70	Teebar Solar Farm	CQ-SQ flow
Woolooga 275/132kV (2x250MVA)	WB	239	237	237	227	228	228		CQ-SQ flow
Columboola 275/132kV (2x375MVA)	S	168	165	153	176	162	150	Surat zone generation	SW generation and 132kV network configuration
Middle Ridge 275/110kV (3x250MVA)	SW	280	273	268	283	280	279	Oakey generation	

Table C.2: Capacity and sample loadings of Powerlink owned 275kV transformers *(continued)*

275kV substation (1)(2)(3)(4) (Number of transformers x MVA nameplate rating)	Zone (5)	Possible MVA loading at Queensland region peak (6)(7)(8)						Dependence other than local load	
		Winter 2017	Winter 2018	Winter 2019	Summer 2017/18	Summer 2018/19	Summer 2019/20	Significant dependence on	Minor dependence on
Tarong 275/132kV (2x90MVA)	SW	32	40	39	21	19	16	Surat zone generation	SW generation and 132kV network configuration
Tarong 275/66kV (2x90MVA)	SW	40	39	39	39	38	38		
Abermain 275/110kV (1x375MVA)	M	147	152	153	186	187	188	110kV transfers to/from Blackstone and Goodna	Tarong flow
Belmont 275/110kV (2x250MVAand 2x375MVA)	M	458	441	457	526	533	532	110kV transfers to/from Loganlea	110kV transfers to/from Rocklea and Swanbank E generation
Blackstone 275/110kV (1x250MVA and 1x240MVA)	M	159	176	179	209	222	221		
Goodna 275/110kV (1x375MVA)	M	140	135	139	178	173	174	110kV transfers to/from Blackstone and Abermain	
Loganlea 275/110kV (2x375MVA)	M	370	371	375	445	451	449	110kV transfers to/from Belmont	110kV transfers to/from Molendinar and Mudgeeraba and Swanbank E generation
Murarrie 275/110kV (2x375MVA)	M	348	341	344	426	427	426		
Palmwoods 275/132kV (2x375MVA)	M	320	321	317	335	331	335		CQ-SQ flow
Rocklea 275/110kV (2x375MVA)	M	335	320	324	421	411	413	110kV transfers to/from South Pine and Belmont	110kV transfers to/from Blackstone and Swanbank E generation
South Pine East 275/110kV (3x375 MVA)	M	587	593	593	689	677	670		
South Pine West 275/110kV (1x375MVA and 1x250MVA)	M	262	251	253	324	316	316		CQ-SQ flow and Swanbank E generation
Molendinar 275/110kV (2x375MVA)	GC	419	420	455	477	513	510	110kV transfers to/from Loganlea and Mudgeeraba	Terranora Interconnector
Mudgeeraba 275/110kV (3x250MVA)	GC	369	369	323	406	353	352	110kV transfers to/from Molendinar and Terranora Interconnector	110kV transfers to/from Loganlea

Table C.2: Capacity and sample loadings of Powerlink owned 275kV transformers *(continued)*

Notes:

(1) Not included are 275/132kV tie transformers within the Calliope River Substation. Loading on these transformers varies considerably with local generation.

(2) Not included are 330/275kV transformers located at Braemar and Middle Ridge substations. Loading on these transformers is dependent on QNI transfer and south west Queensland generation.

(3) To protect the confidentiality of specific customer loads, transformers supplying a single customer are not included.

(4) Nameplate based on present ratings. Cyclic overload capacities above nameplate ratings are assigned to transformers based on ambient temperature, load cycle patterns and transformer design.

(5) Zone abbreviations are defined in Appendix A.

(6) Substation loadings are derived from the assumed generation dispatch cases shown within figures C.3 to C.20. The loadings are estimated for system normal operation and are based on the existing network configuration and committed projects. MVA loadings for transformers depend on power factor and may be different under other generation patterns, outage conditions, local or zone maximum demand times or different availability of local and dowstream capacitor banks.

(7) Substation loadings are the maximum of each of the northerly/zero/southerly QNI scenarios for each year/season shown within the assumed generation dispatch cases in figures C.3 to C.20.

(8) Under outage conditions the MVA transformer loadings at substations may be lower due to the interconnected nature of the sub-transmission network or operational switching strategies.

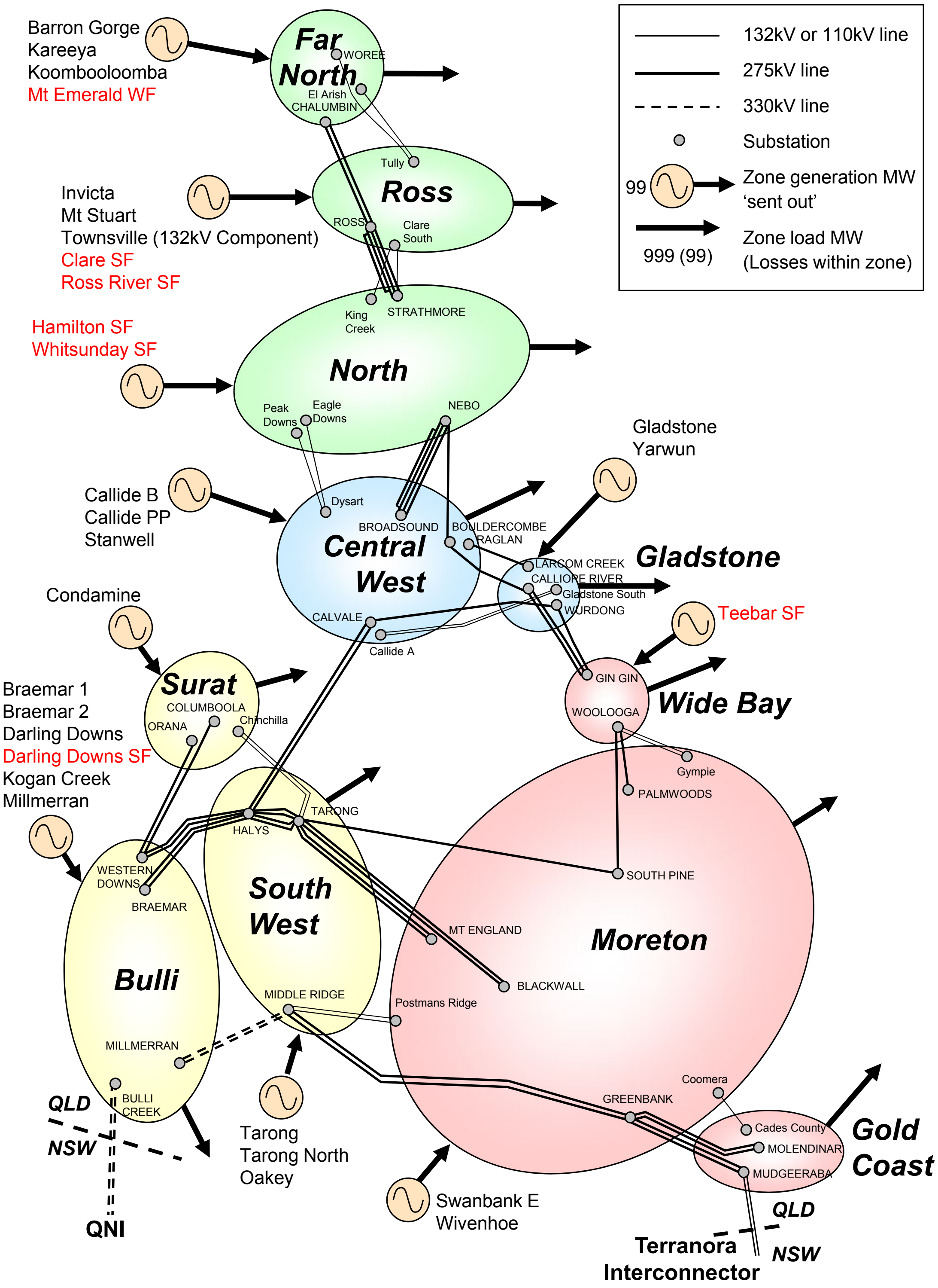


Figure C.1 Generation and load legend for figures C.3 to C.20

Figure C.2 Grid section legend for figures C.3 to C.20

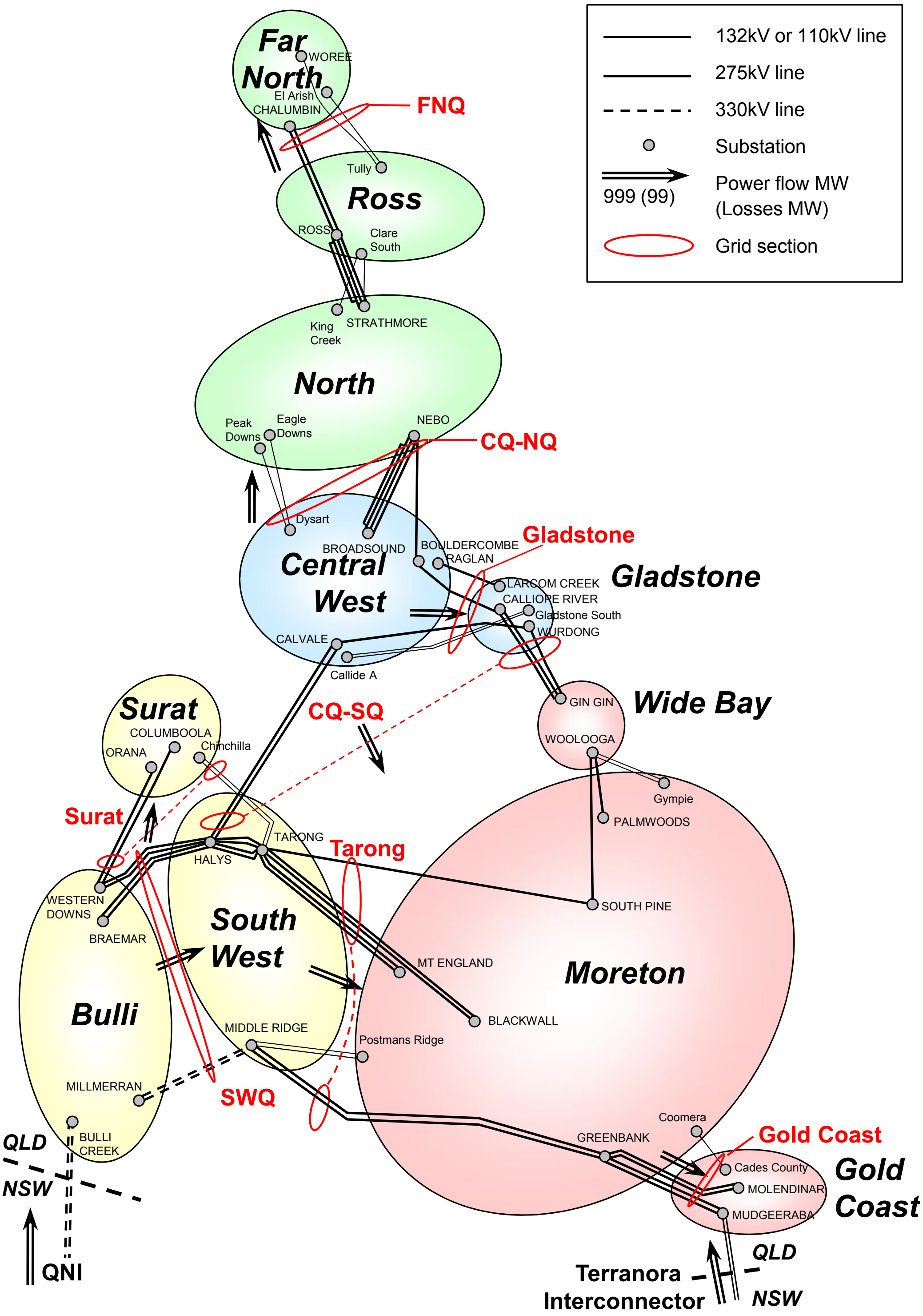
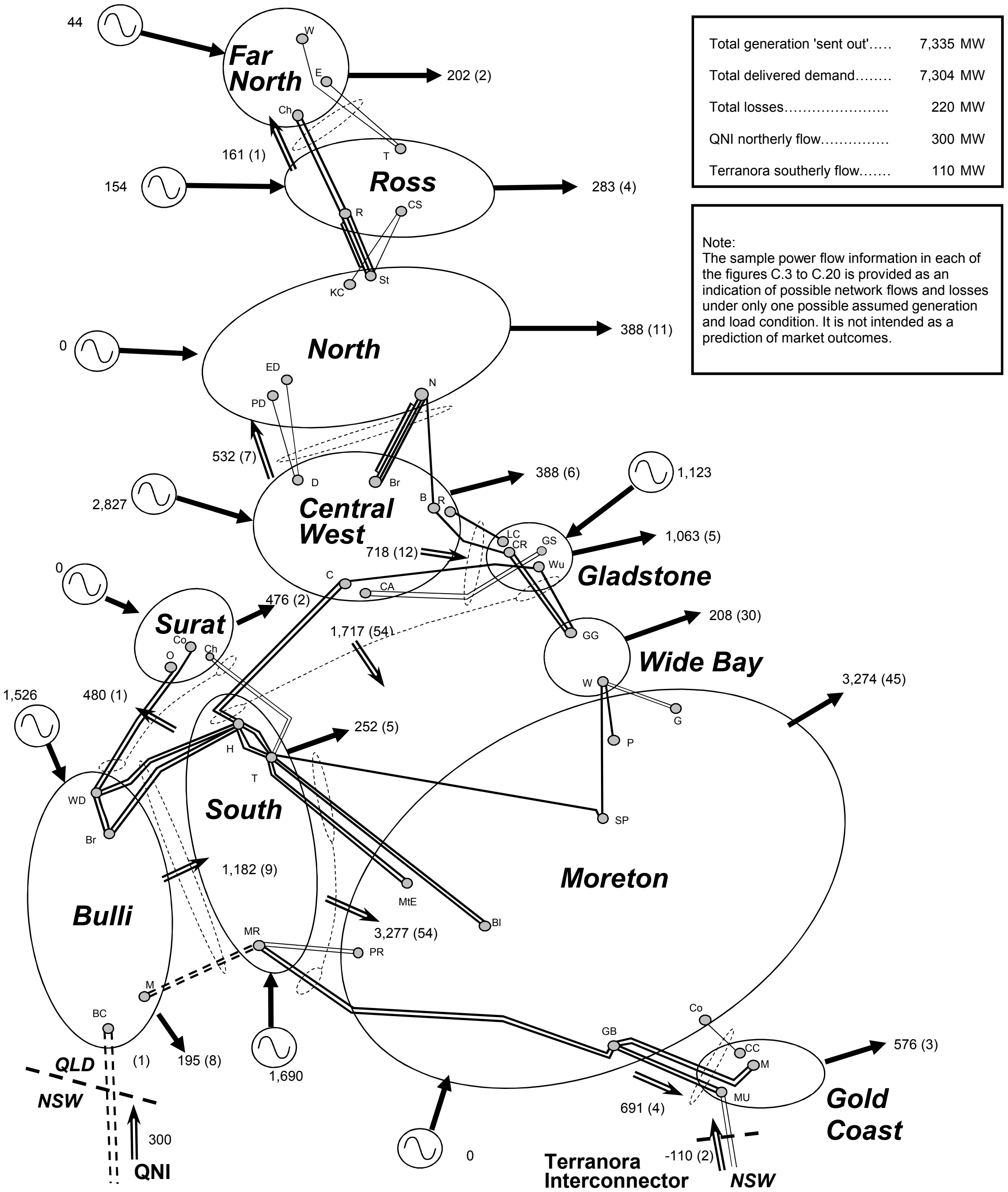


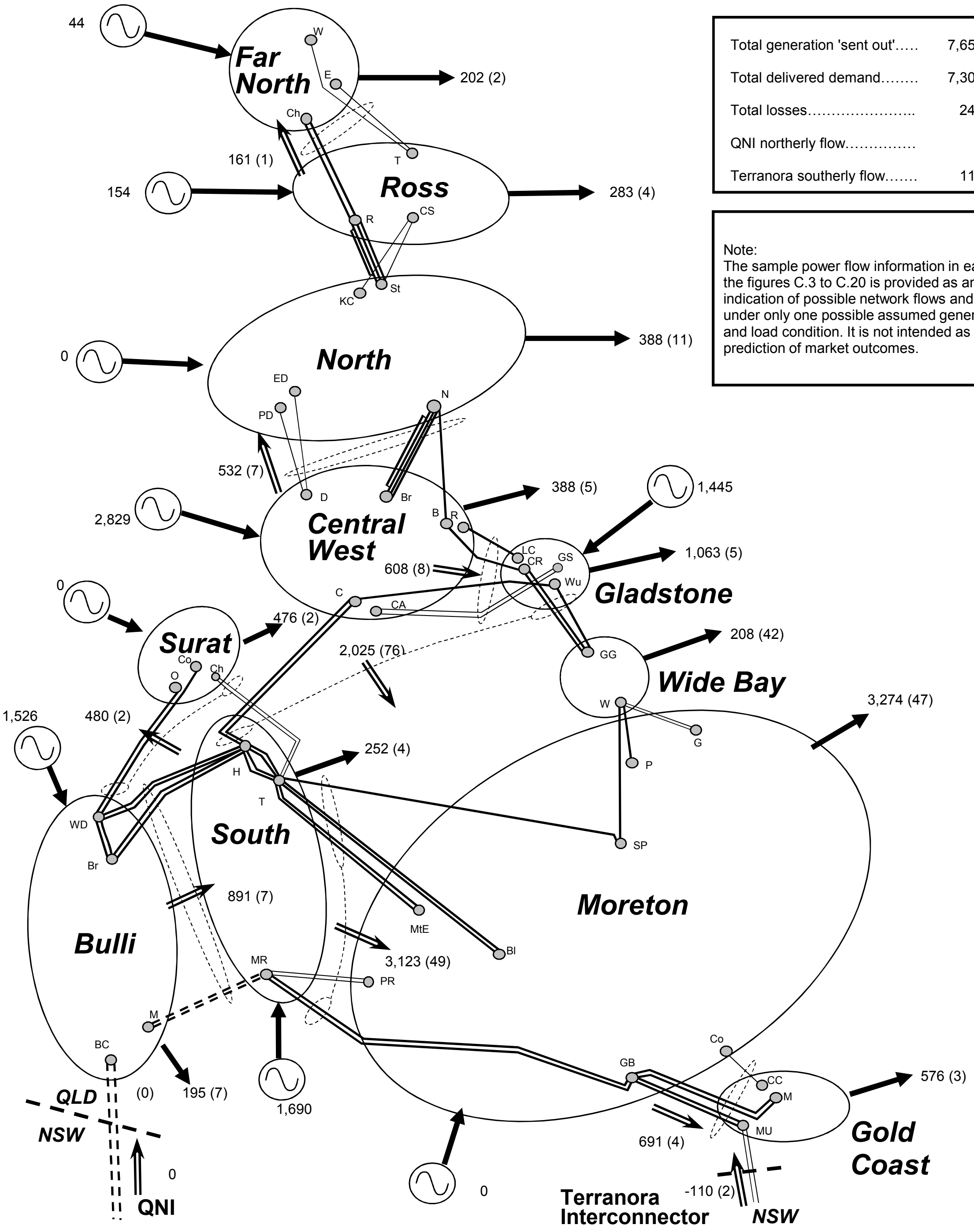
Figure C.3 Winter 2017 Queensland maximum demand 300MW northerly QNI flow



Total generation 'sent out'…..	7,335 MW
Total delivered demand……..	7,304 MW
Total losses…………………..	220 MW
QNI northerly flow……………	300 MW
Terranora southerly flow…….	110 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

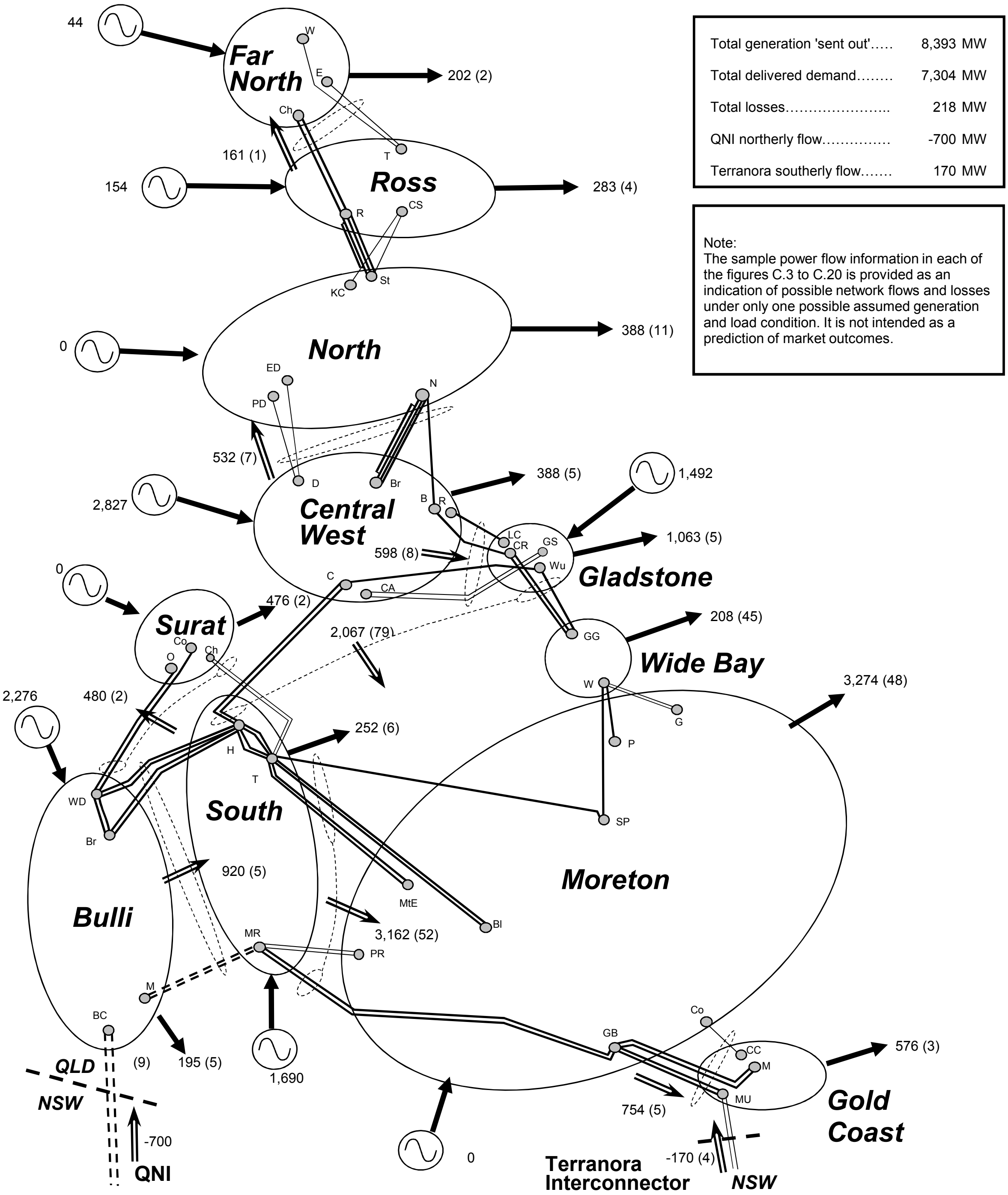
Figure C.4 Winter 2017 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'.....	7,659 MW
Total delivered demand........	7,304 MW
Total losses.......................	244 MW
QNI northerly flow..............	0 MW
Terranora southerly flow.......	110 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

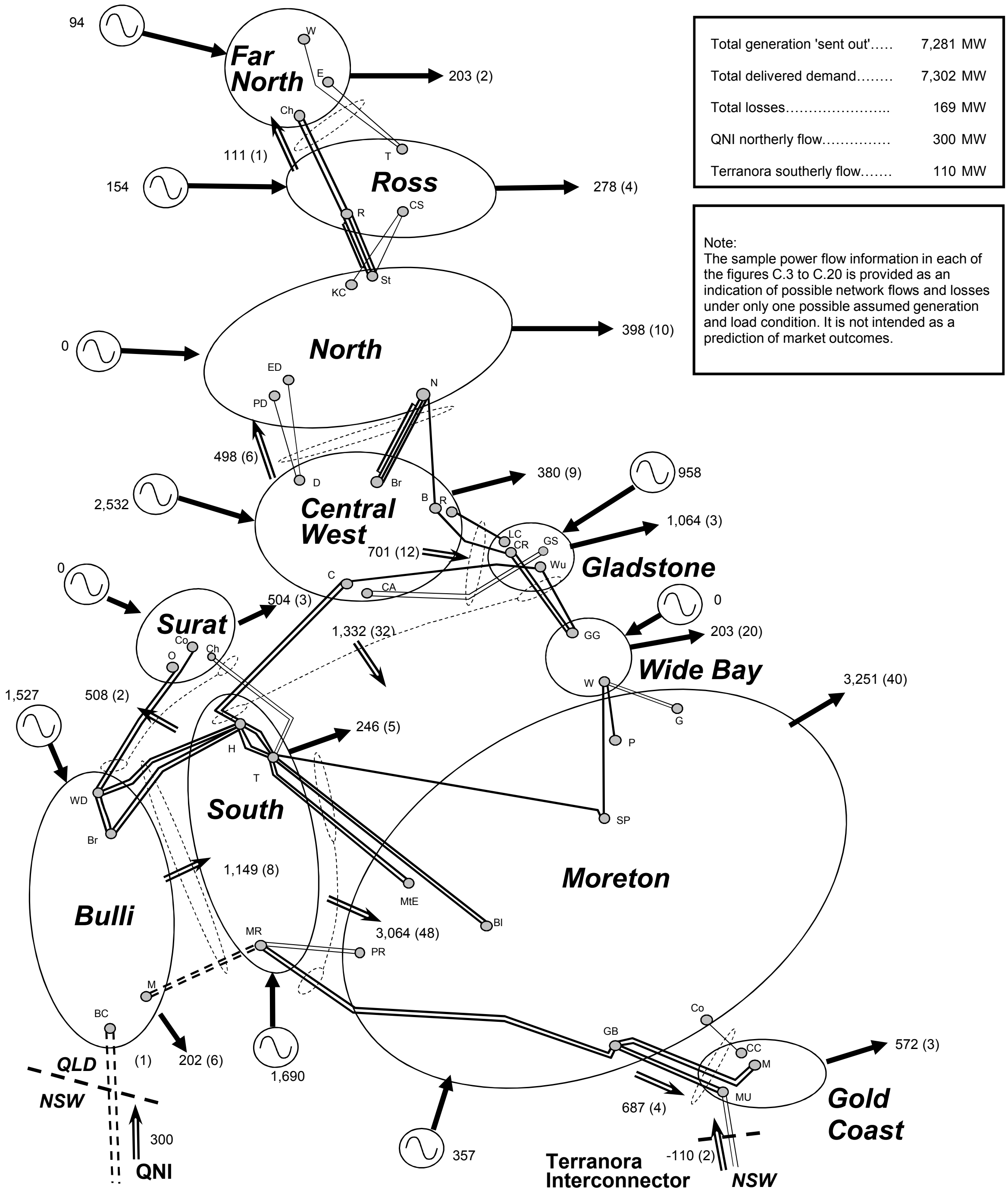
Figure C.5 Winter 2017 Queensland maximum demand 700MW southerly QNI flow



Total generation 'sent out'…..	8,393 MW
Total delivered demand……..	7,304 MW
Total losses…………………..	218 MW
QNI northerly flow…………..	-700 MW
Terranora southerly flow…….	170 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

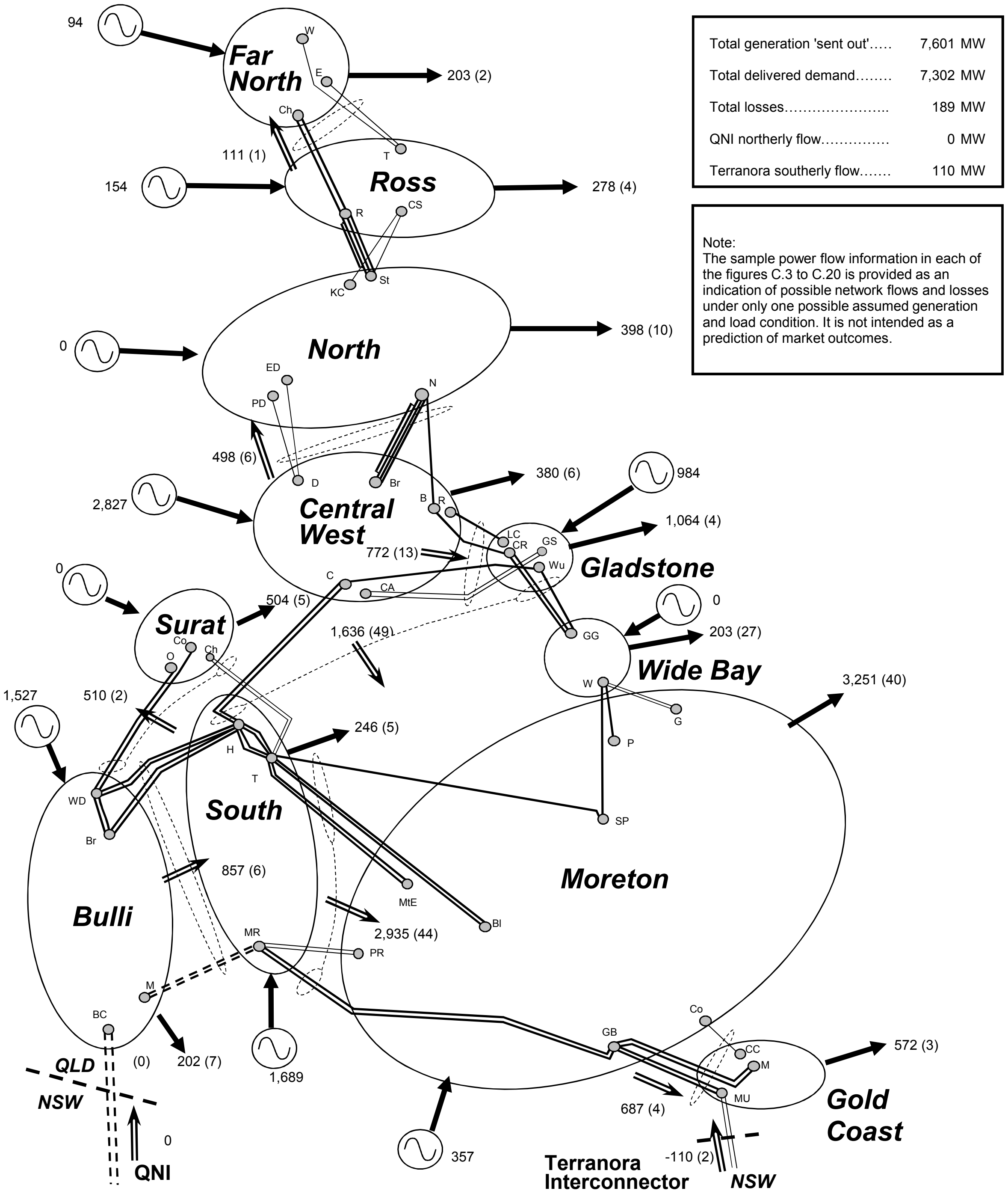
Figure C.6 Winter 2018 Queensland maximum demand 300MW northerly QNI flow



Total generation 'sent out'…..	7,281 MW
Total delivered demand……..	7,302 MW
Total losses…………………..	169 MW
QNI northerly flow…………..	300 MW
Terranora southerly flow…….	110 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

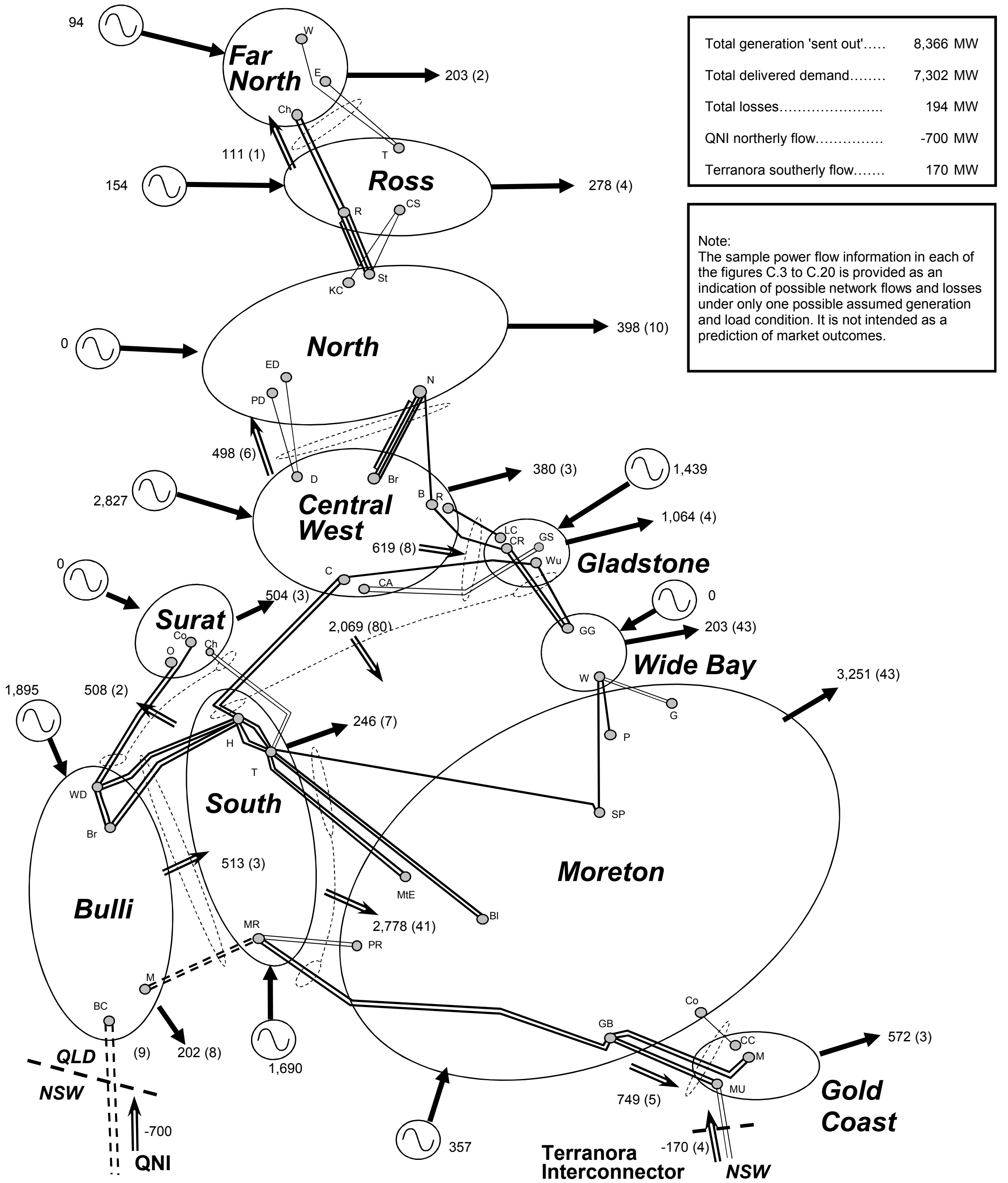
Figure C.7 Winter 2018 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'…..	7,601 MW
Total delivered demand……..	7,302 MW
Total losses…………………..	189 MW
QNI northerly flow…………..	0 MW
Terranora southerly flow…….	110 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

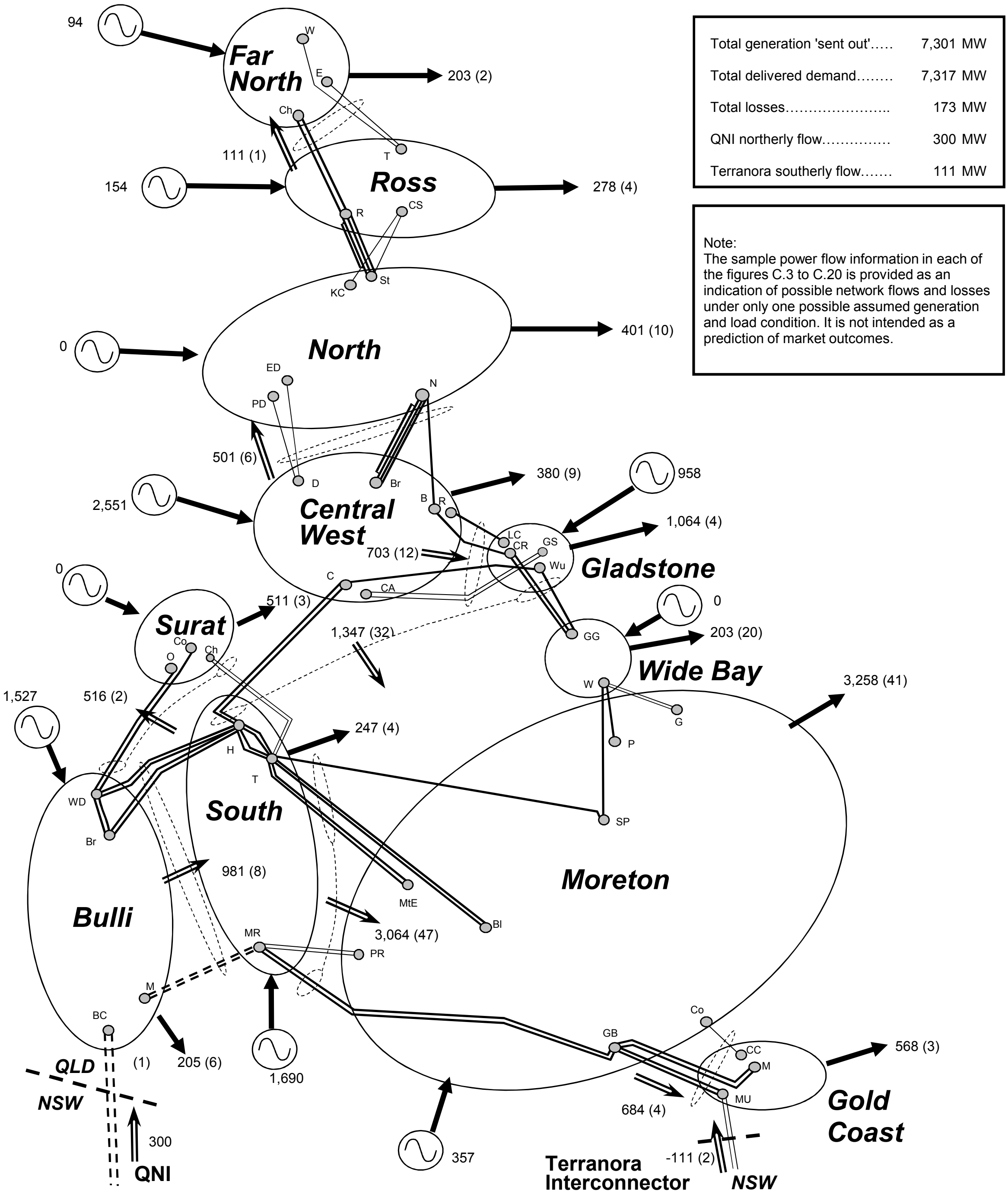
Figure C.8 Winter 2018 Queensland maximum demand 700MW southerly QNI flow



Total generation 'sent out'.....	8,366 MW
Total delivered demand........	7,302 MW
Total losses.......................	194 MW
QNI northerly flow..............	-700 MW
Terranora southerly flow.......	170 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

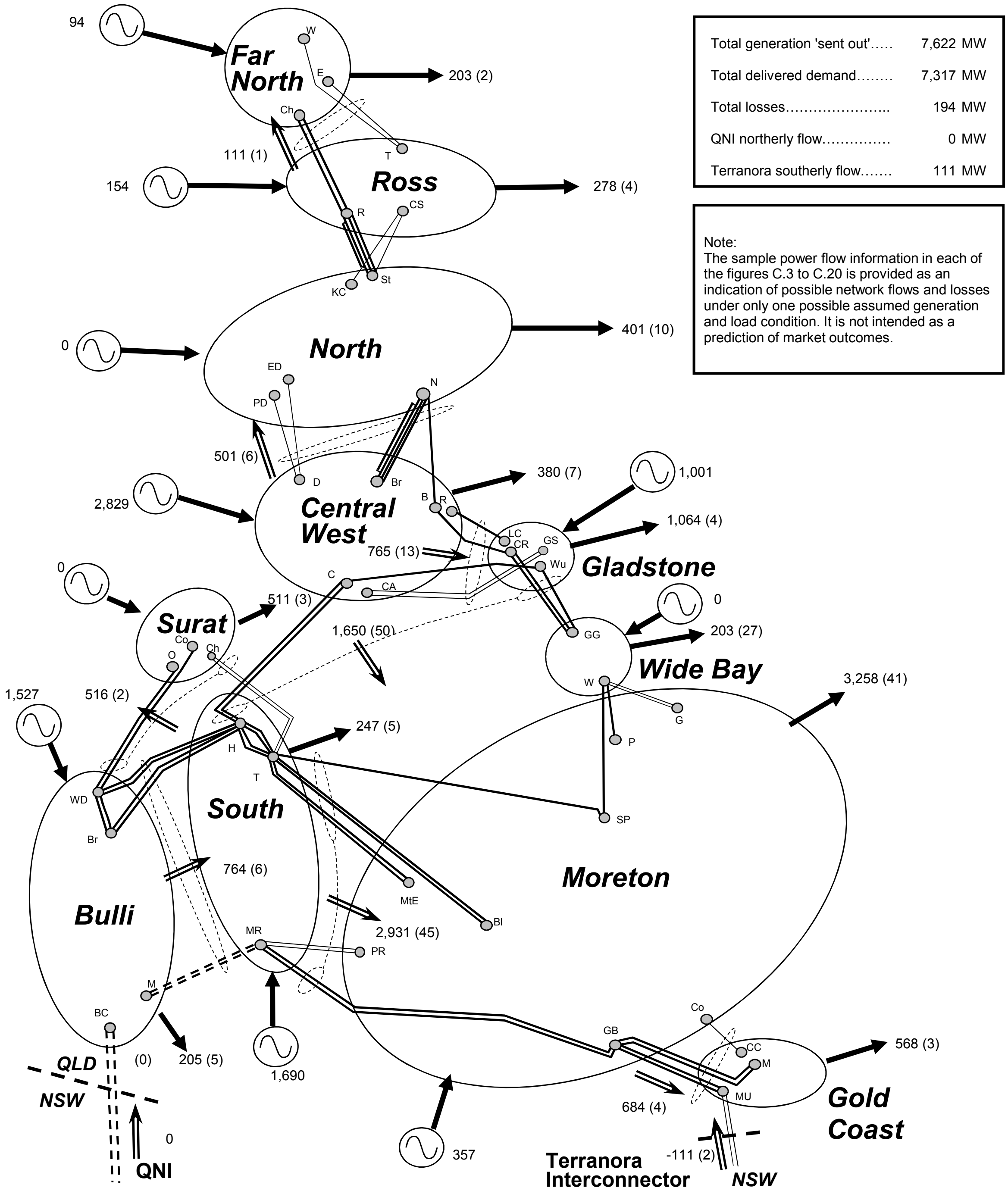
Figure C.9 Winter 2019 Queensland maximum demand 300MW northerly QNI flow



Total generation 'sent out'…..	7,301 MW
Total delivered demand……..	7,317 MW
Total losses…………………..	173 MW
QNI northerly flow…………..	300 MW
Terranora southerly flow…….	111 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

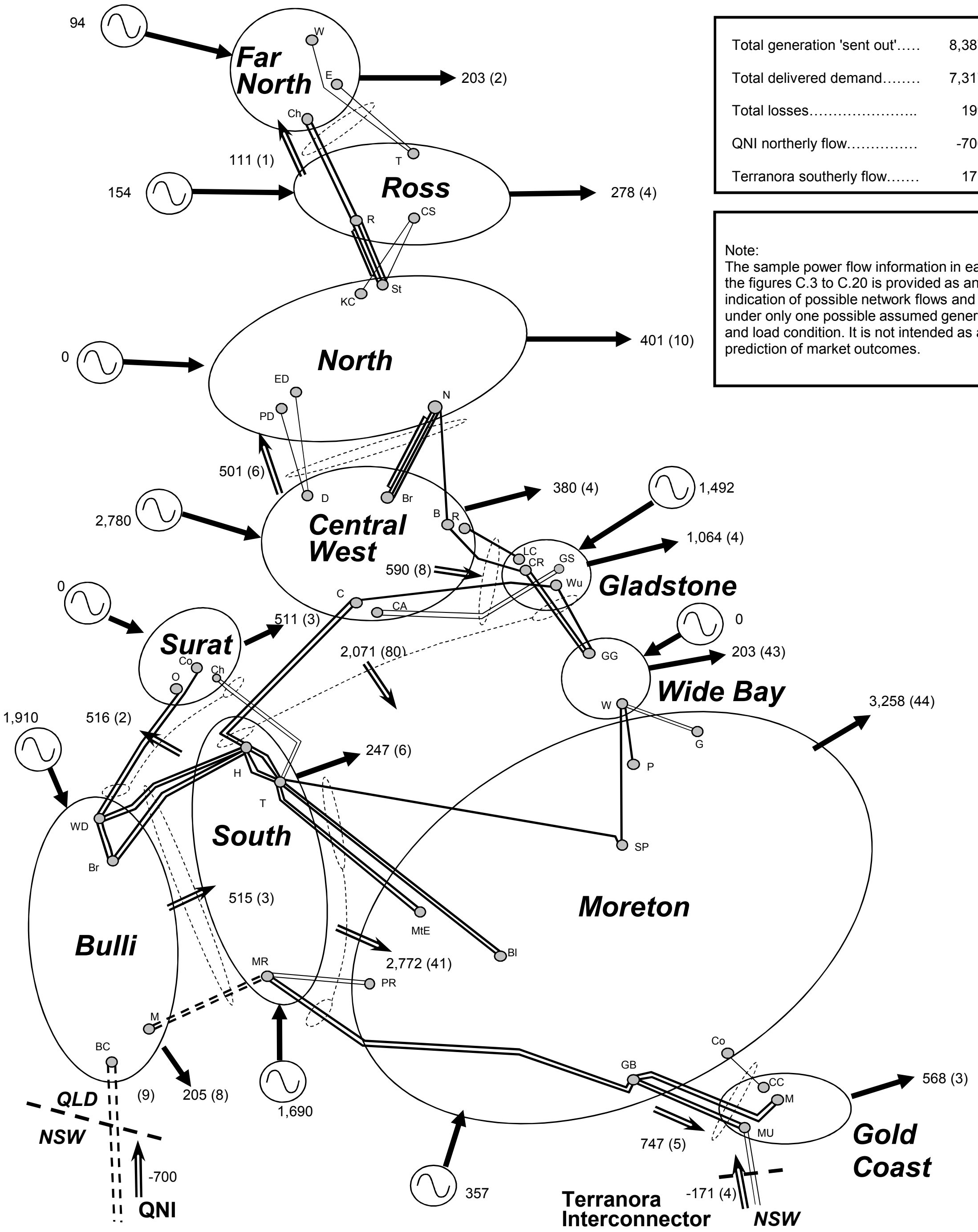
Figure C.10 Winter 2019 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'.....	7,622 MW
Total delivered demand........	7,317 MW
Total losses.......................	194 MW
QNI northerly flow..............	0 MW
Terranora southerly flow.......	111 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

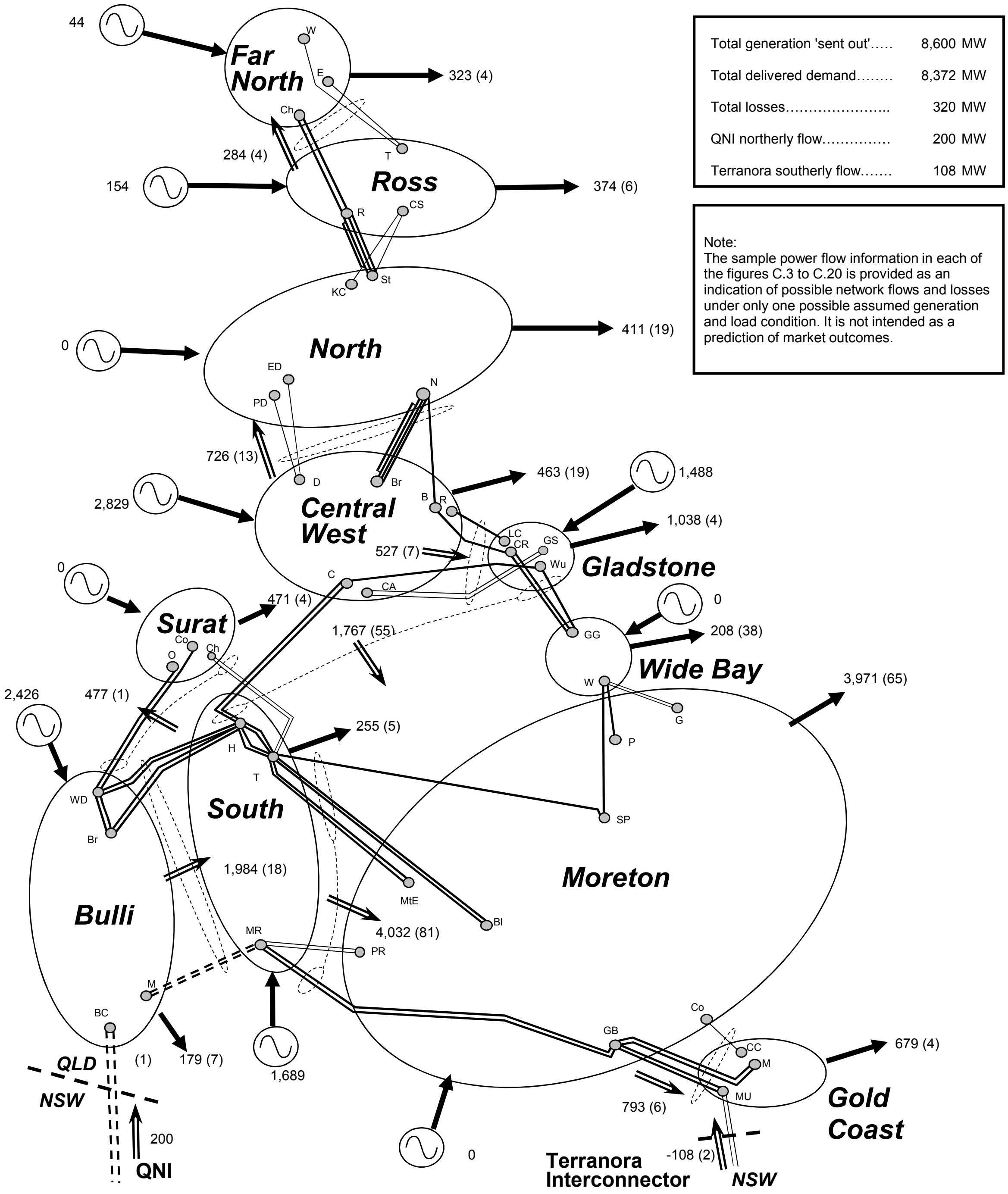
Figure C.11 Winter 2019 Queensland maximum demand 700MW southerly QNI flow



Total generation 'sent out'…..	8,387 MW
Total delivered demand……..	7,317 MW
Total losses…………………..	199 MW
QNI northerly flow……………	-700 MW
Terranora southerly flow…….	171 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

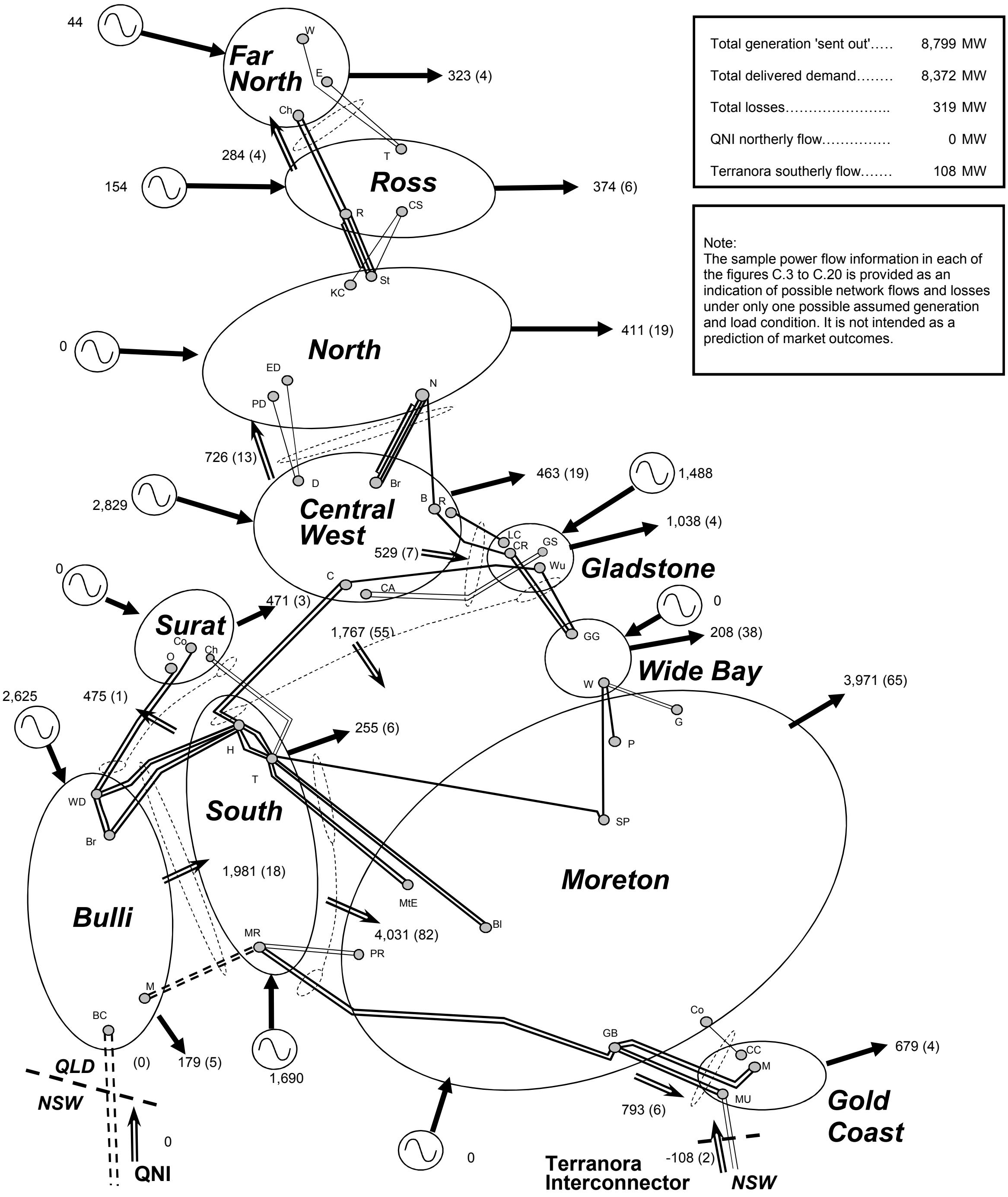
Figure C.12 Summer 2017/18 Queensland maximum demand 200MW northerly QNI flow



Total generation 'sent out'…..	8,600 MW
Total delivered demand……..	8,372 MW
Total losses…………………..	320 MW
QNI northerly flow…………..	200 MW
Terranora southerly flow…….	108 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

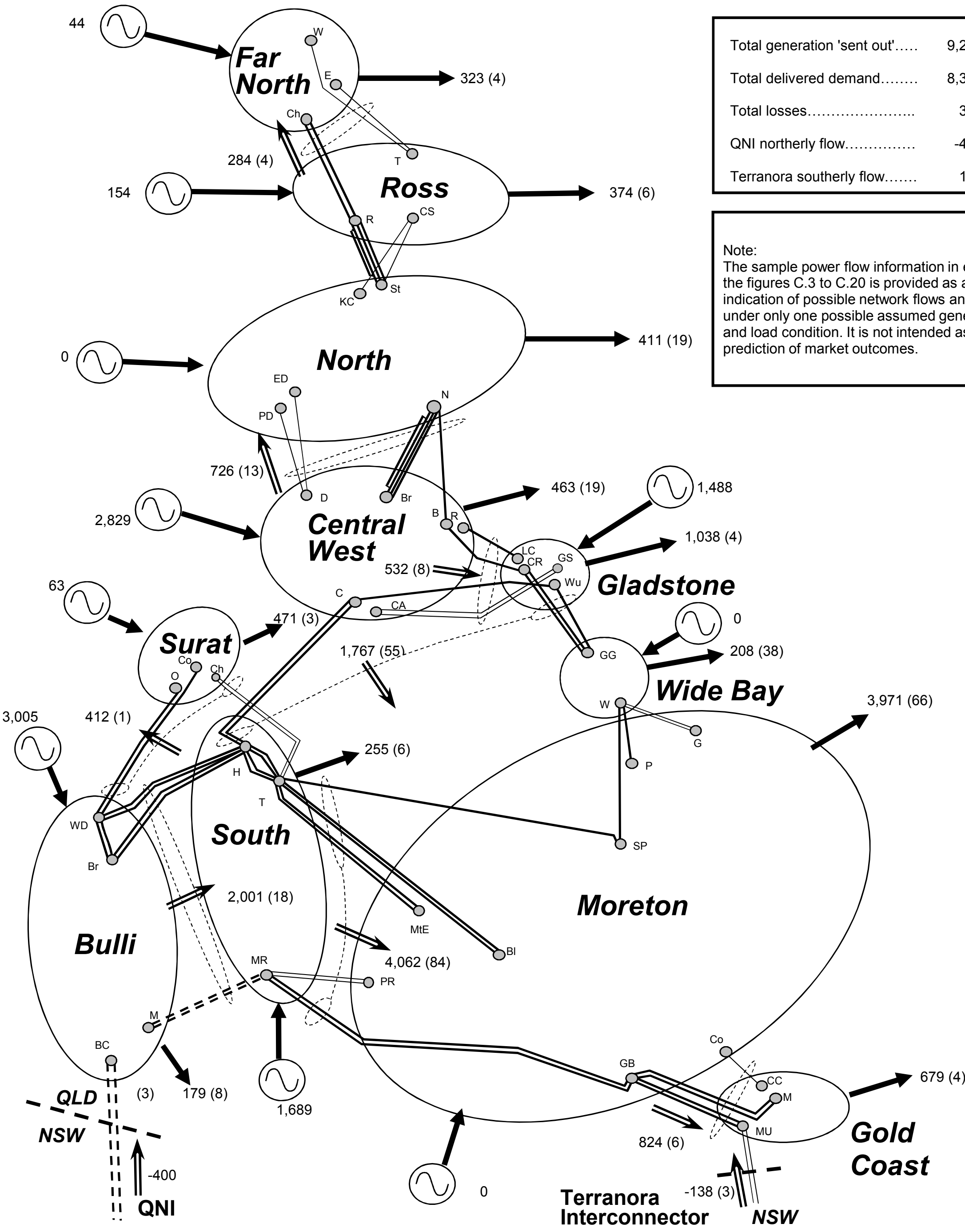
Figure C.13 Summary 2017/18 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'…..	8,799 MW
Total delivered demand……..	8,372 MW
Total losses…………………..	319 MW
QNI northerly flow…………..	0 MW
Terranora southerly flow…….	108 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

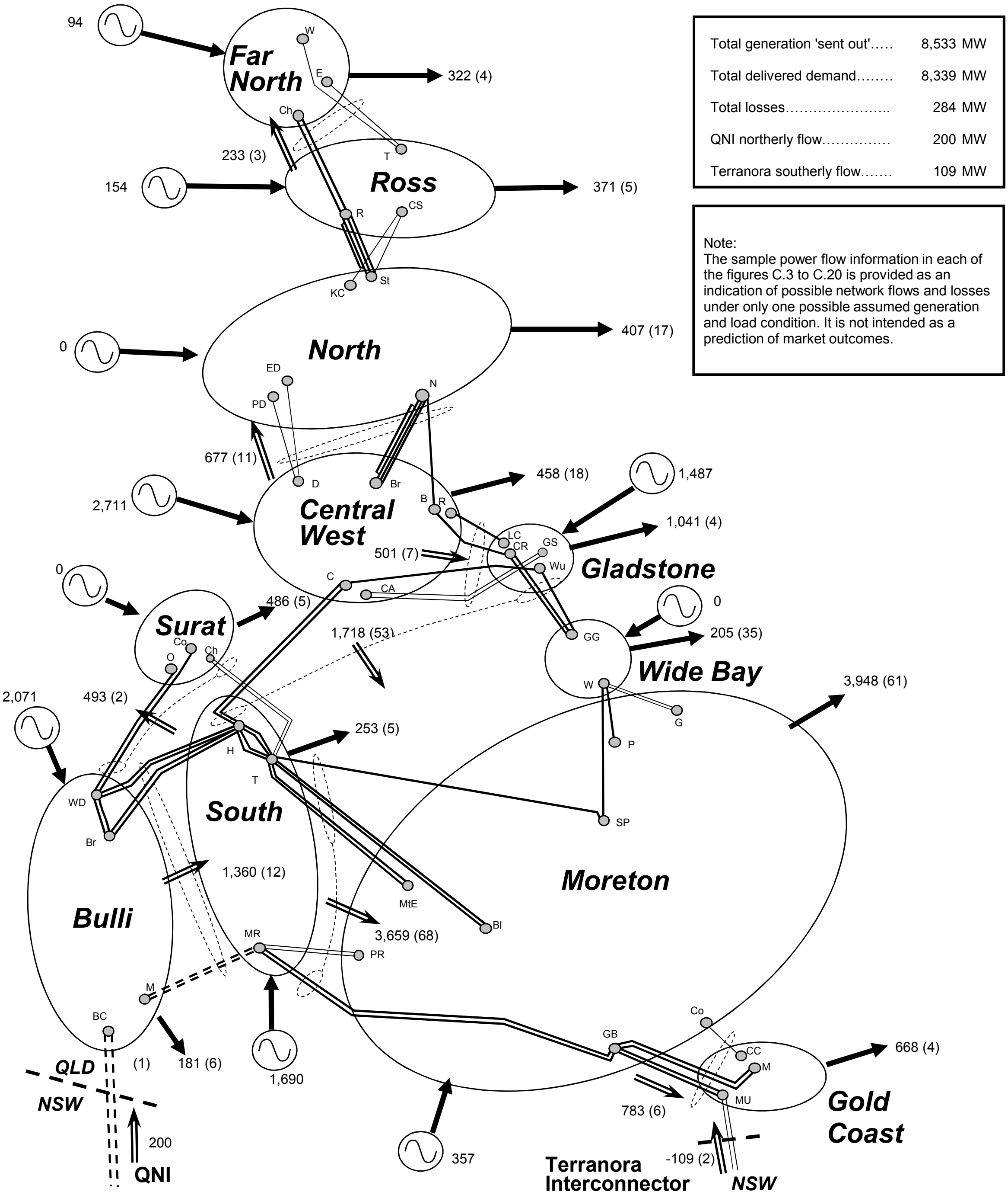
Figure C.14 Summary 2017/18 Queensland maximum demand 400MW southerly QNI flow



Total generation 'sent out'…..	9,212 MW
Total delivered demand……..	8,372 MW
Total losses…………………..	301 MW
QNI northerly flow…………..	-400 MW
Terranora southerly flow…….	138 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

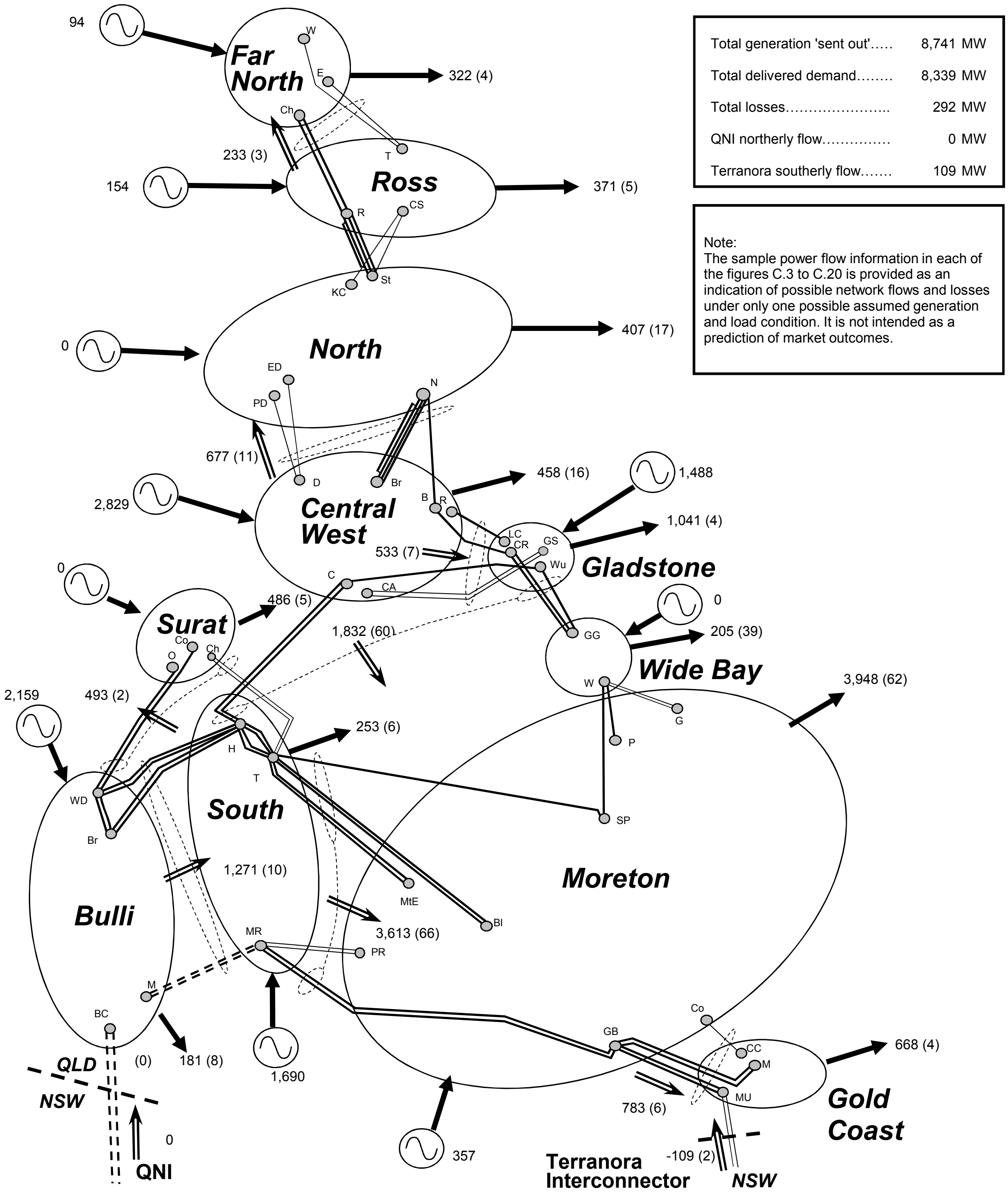
Figure C.15 Summer 2018/19 Queensland maximum demand 200MW northerly QNI flow



Total generation 'sent out'…..	8,533 MW
Total delivered demand……..	8,339 MW
Total losses…………………..	284 MW
QNI northerly flow…………..	200 MW
Terranora southerly flow…….	109 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

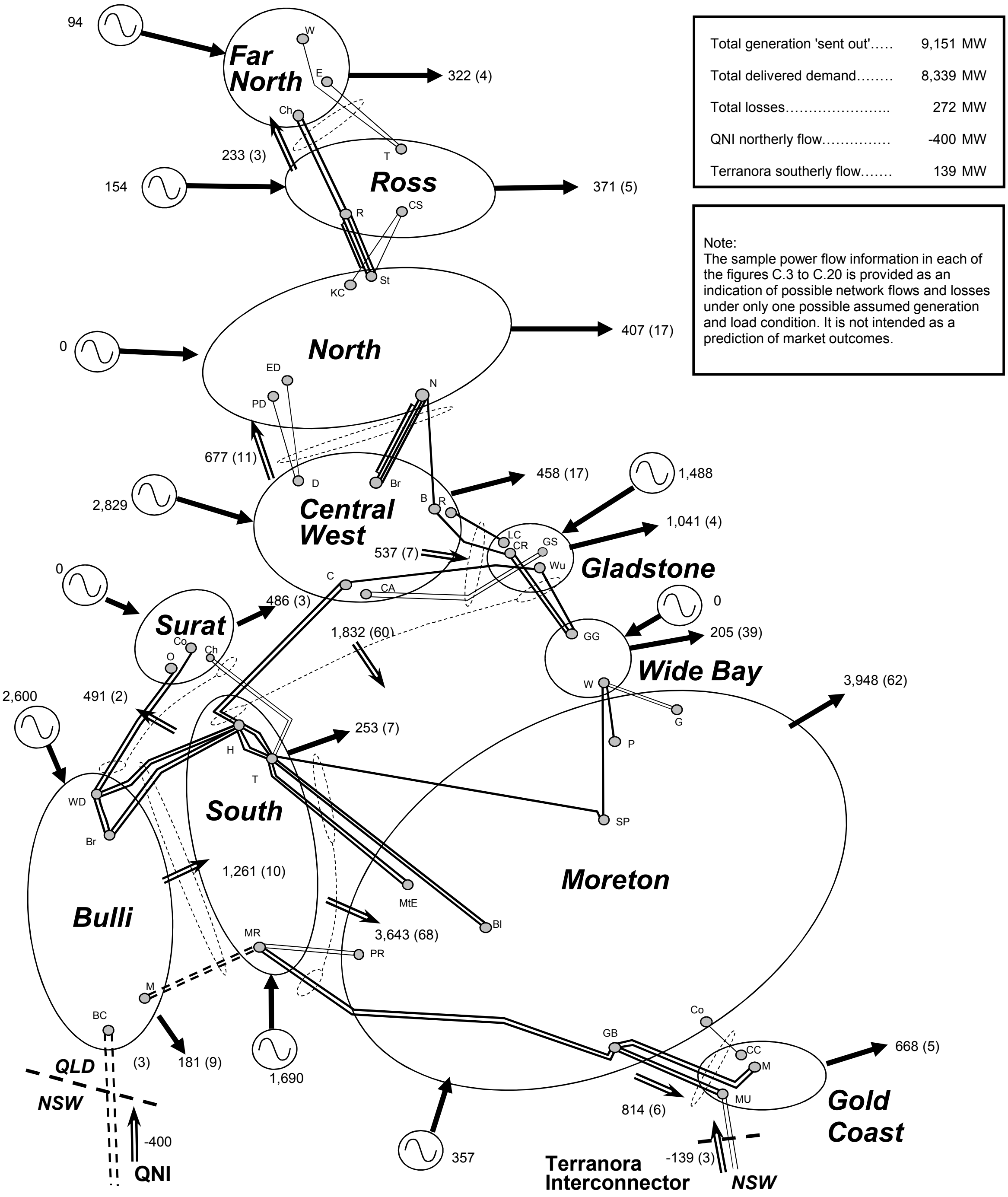
Figure C.16 Summer 2018/19 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'…..	8,741 MW
Total delivered demand……..	8,339 MW
Total losses…………………..	292 MW
QNI northerly flow……………	0 MW
Terranora southerly flow…….	109 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

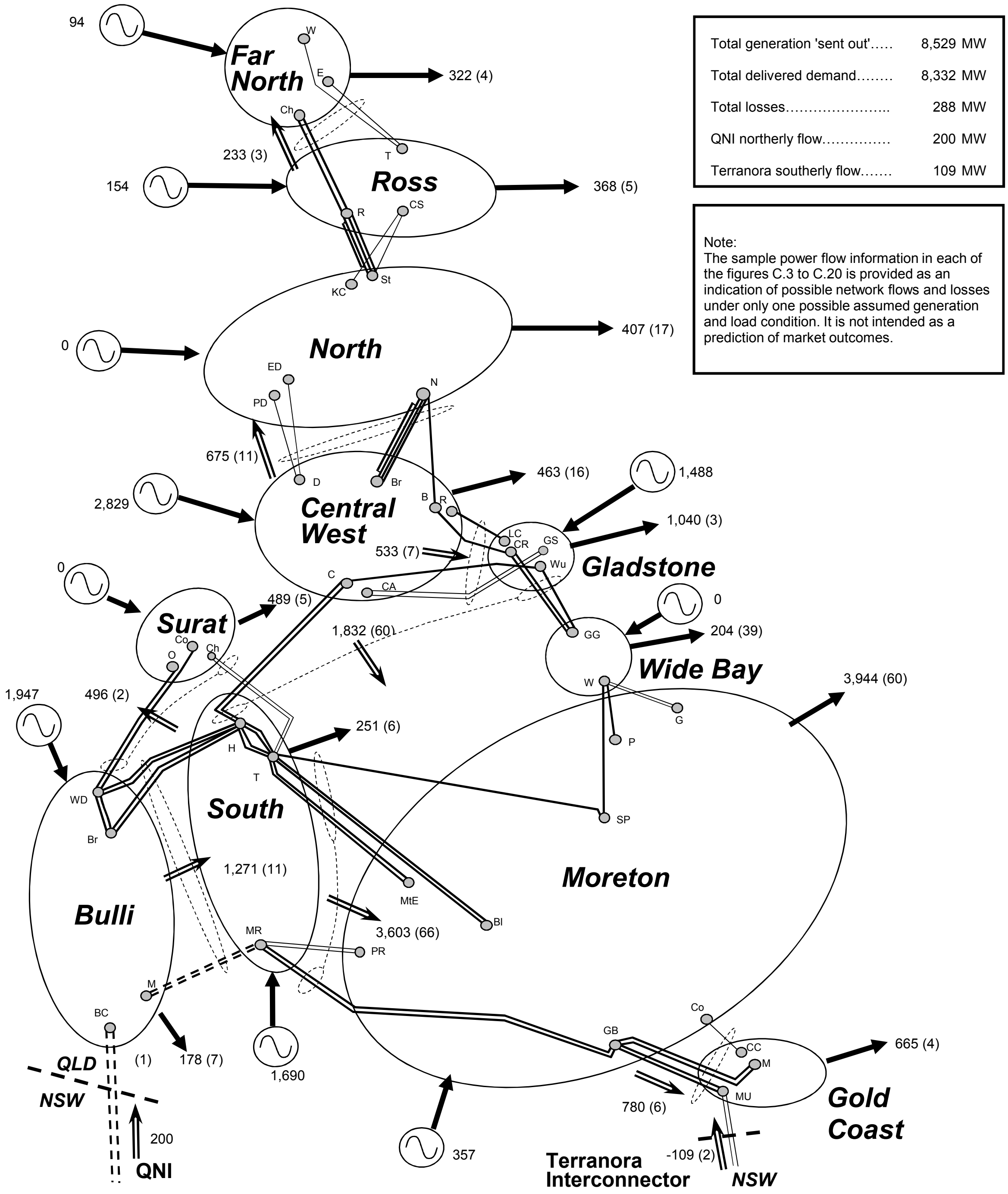
Figure C.17 Summer 2018/19 Queensland maximum demand 400MW southerly QNI flow



Total generation 'sent out'…..	9,151 MW
Total delivered demand……..	8,339 MW
Total losses…………………..	272 MW
QNI northerly flow……………	-400 MW
Terranora southerly flow…….	139 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

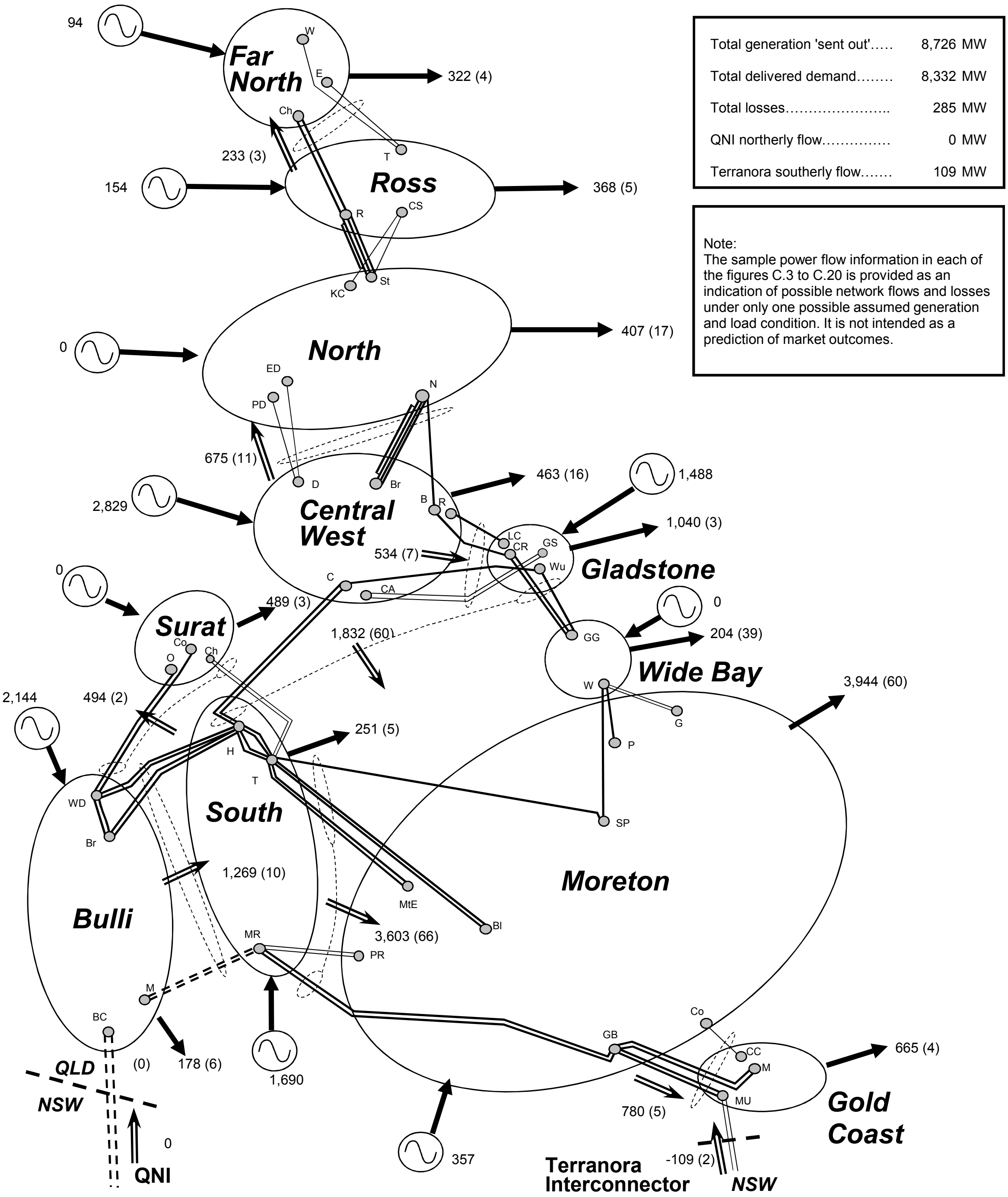
Figure C.18 Summer 2019/20 Queensland maximum demand 200MW northerly QNI flow



Total generation 'sent out'…..	8,529 MW
Total delivered demand……..	8,332 MW
Total losses…………………..	288 MW
QNI northerly flow…………..	200 MW
Terranora southerly flow…….	109 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

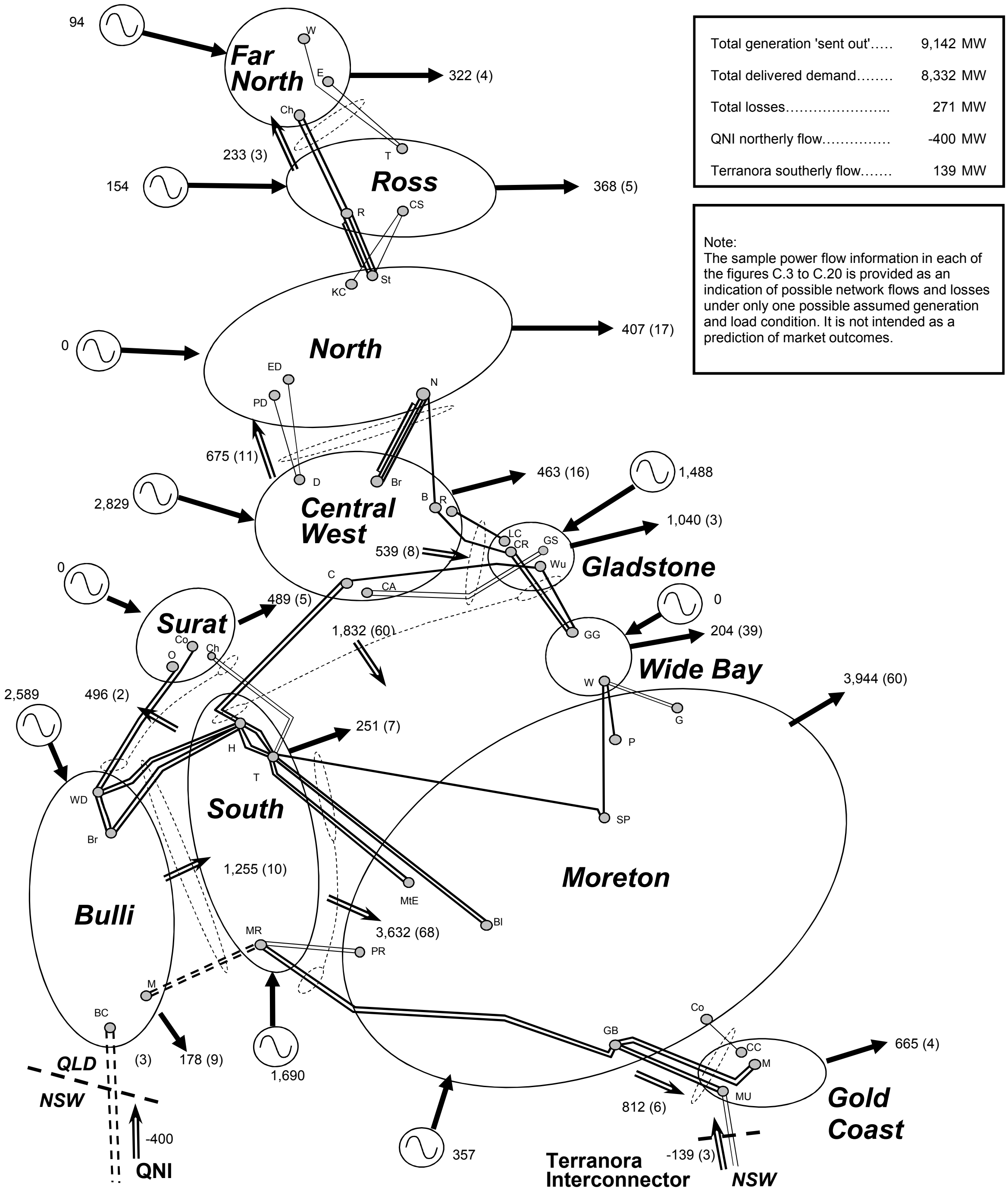
Figure C.19 Summer 2019/20 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'…..	8,726 MW
Total delivered demand……..	8,332 MW
Total losses…………………..	285 MW
QNI northerly flow……………	0 MW
Terranora southerly flow…….	109 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Figure C.20 Summer 2019/20 Queensland maximum demand 400MW southerly QNI flow



Total generation 'sent out'.....	9,142 MW
Total delivered demand........	8,332 MW
Total losses.......................	271 MW
QNI northerly flow..............	-400 MW
Terranora southerly flow.......	139 MW

Note:
The sample power flow information in each of the figures C.3 to C.20 is provided as an indication of possible network flows and losses under only one possible assumed generation and load condition. It is not intended as a prediction of market outcomes.

Appendix D – Limit equations

This appendix lists the Queensland intra-regional limit equations, derived by Powerlink, valid at the time of publication. The Australian Energy Market Operator (AEMO) defines other limit equations for the Queensland Region in its market dispatch systems.

It should be noted that these equations are continually under review to take into account changing market and network conditions.

Please contact Powerlink to confirm the latest form of the relevant limit equation if required.

Table D.1 **Far North Queensland (FNQ) grid section voltage stability equation**

Measured variable	Coefficient
Constant term (intercept)	-19.00
FNQ demand percentage (1) (2)	17.00
Total MW generation at Barron Gorge, Kareeya and Koombooloomba	-0.46
Total MW generation at Mt Stuart and Townsville	0.13
AEMO Constraint ID	**Q^NIL_FNQ**

Notes:

(1) FNQ demand percentage $= \frac{\text{Far North zone demand}}{\text{North Queensland area demand}} \times 100$

Far North zone demand (MW) = FNQ grid section transfer + (Barron Gorge + Kareeya + Koombooloomba) generation

North Queensland area demand (MW) = CQ-NQ grid section transfer + (Barron Gorge + Kareeya + Koombooloomba + Townsville + Mt Stuart + Invicta + Mackay) generation

(2) The FNQ demand percentage is bound between 22 and 31.

Table D.2 Central to North Queensland grid section voltage stability equations

Measured variable	Coefficient	
	Equation 1	Equation 2
	Feeder contingency	Townsville contingency (1)
Constant term (intercept)	1,500	1,650
Total MW generation at Barron Gorge, Kareeya and Koombooloomba	0.321	–
Total MW generation at Townsville	0.172	-1.000
Total MW generation at Mt Stuart	-0.092	-0.136
Number of Mt Stuart units on line [0 to 3]	22.447	14.513
Total MW generation at Mackay	-0.700	-0.478
Total nominal MVAr shunt capacitors on line within nominated Ross area locations (2)	0.453	0.440
Total nominal MVAr shunt reactors on line within nominated Ross area locations (3)	-0.453	-0.440
Total nominal MVAr shunt capacitors on line within nominated Strathmore area locations (4)	0.388	0.431
Total nominal MVAr shunt reactors on line within nominated Strathmore area locations (5)	-0.388	-0.431
Total nominal MVAr shunt capacitors on line within nominated Nebo area locations (6)	0.296	0.470
Total nominal MVAr shunt reactors on line within nominated Nebo area locations (7)	-0.296	-0.470
Total nominal MVAr shunt capacitors available to the Nebo Q optimiser (8)	0.296	0.470
Total nominal MVAr shunt capacitors on line not available to the Nebo Q optimiser (8)	0.296	0.470
AEMO Constraint ID	**Q^NIL_CN_FDR**	**Q^NIL_CN_GT**

Notes:

(1) This limit is applicable only if Townsville Power Station is generating.

(2) The shunt capacitor bank locations, nominal sizes and quantities for the Ross area comprise the following:

Ross 132kV	1 x 50MVAr
Townsville South 132kV	2 x 50MVAr
Dan Gleeson 66kV	2 x 24MVAr
Garbutt 66kV	2 x 15MVAr

(3) The shunt reactor bank locations, nominal sizes and quantities for the Ross area comprise the following:

Ross 275kV	2 x 84MVAr, 2 x 29.4MVAr

(4) The shunt capacitor bank locations, nominal sizes and quantities for the Strathmore area comprise the following:

Newlands 132kV	1 x 25MVAr
Clare South 132kV	1 x 20MVAr
Collinsville North 132kV	1 x 20MVAr

(5) The shunt reactor bank locations, nominal sizes and quantities for the Strathmore area comprise the following:

Strathmore 275kV	1 x 84MVAr

(6) The shunt capacitor bank locations, nominal sizes and quantities for the Nebo area comprise the following:

Pioneer Valley 132kV	1 x 30MVAr
Kemmis 132kV	1 x 30MVAr
Dysart 132kV	2 x 25MVAr
Alligator Creek 132kV	1 x 20MVAr
Mackay 33kV	2 x 15MVAr

(7) The shunt reactor bank locations, nominal sizes and quantities for the Nebo area comprise the following:

Nebo 275kV	1 x 84MVAr, 1 x 30MVAr, 1 x 20.2MVAr

(8) The shunt capacitor banks nominal sizes and quantities for which may be available to the Nebo Q optimiser comprise the following:

Nebo 275kV	2 x 120MVAr

Table D.3 Central to South Queensland grid section voltage stability equations

Measured variable	Coefficient
Constant term (intercept)	1,015
Total MW generation at Gladstone 275kV and 132kV	0.1407
Number of Gladstone 275kV units on line [2 to 4]	57.5992
Number of Gladstone 132kV units on line [1 to 2]	89.2898
Total MW generation at Callide B and Callide C	0.0901
Number of Callide B units on line [0 to 2]	29.8537
Number of Callide C units on line [0 to 2]	63.4098
Total MW generation in southern Queensland (1)	-0.0650
Number of 90MVAr capacitor banks available at Boyne Island [0 to 2]	51.1534
Number of 50MVAr capacitor banks available at Boyne Island [0 to 1]	25.5767
Number of 120MVAr capacitor banks available at Wurdong [0 to 3]	52.2609
Number of 120MVAr capacitor banks available at Gin Gin [0 to 1]	63.5367
Number of 50MVAr capacitor banks available at Gin Gin [0 to 1]	31.5525
Number of 120MVAr capacitor banks available at Woolooga [0 to 1]	47.7050
Number of 50MVAr capacitor banks available at Woolooga [0 to 2]	22.9875
Number of 120MVAr capacitor banks available at Palmwoods [0 to 1]	30.7759
Number of 50MVAr capacitor banks available at Palmwoods [0 to 4]	14.2253
Number of 120MVAr capacitor banks available at South Pine [0 to 4]	9.0315
Number of 50MVAr capacitor banks available at South Pine [0 to 4]	3.2522
Equation lower limit	**1,550**
Equation upper limit	**2,100 (2)**
AEMO Constraint ID	**Q^^NIL_CS, Q::NIL_CS**

Notes:

(1) Southern Queensland generation term refers to summated active power generation at Swanbank E, Wivenhoe, Tarong, Tarong North, Condamine, Roma, Kogan Creek, Braemar 1, Braemar 2, Darling Downs, Oakey, Millmerran and Terranora Interconnector and QNI transfers (positive transfer denotes northerly flow).

(2) The upper limit is due to a transient stability limitation between central and southern Queensland areas.

Table D.4 Tarong grid section voltage stability equations

Measured variable	Coefficient	
	Equation 1	Equation 2
	Calvale-Halys contingency	Tarong-Blackwall contingency
Constant term (intercept) (1)	740	1,124
Total MW generation at Callide B and Callide C	0.0346	0.0797
Total MW generation at Gladstone 275kV and 132kV	0.0134	–
Total MW generation at Tarong, Tarong North, Roma, Condamine, Kogan Creek, Braemar 1, Braemar 2, Darling Downs, Oakey, Millmerran and QNI transfer (2)	0.8625	0.7945
Surat/Braemar demand	-0.8625	-0.7945
Total MW generation at Wivenhoe and Swanbank E	-0.0517	-0.0687
Active power transfer (MW) across Terranora Interconnector (2)	-0.0808	-0.1287
Number of 200MVAr capacitor banks available (3)	7.6683	16.7396
Number of 120MVAr capacitor banks available (4)	4.6010	10.0438
Number of 50MVAr capacitor banks available (5)	1.9171	4.1849
Reactive to active demand percentage (6) (7)	-2.9964	-5.7927
Equation lower limit	**3,200**	**3,200**
AEMO Constraint ID	**Q^^NIL_TR_CLHA**	**Q^^NIL_TR_TRBK**

Notes:

(1) Equations 1 and 2 are offset by -100MW and -150MW respectively when the Middle Ridge to Abermain 110kV loop is run closed.

(2) Positive transfer denotes northerly flow.

(3) There are currently 4 capacitor banks of nominal size 200MVAr which may be available within this area.

(4) There are currently 18 capacitor banks of nominal size 120MVAr which may be available within this area.

(5) There are currently 38 capacitor banks of nominal size 50MVAr which may be available within this area.

(6) Reactive to active demand percentage $= \frac{\text{Zone reactive demand}}{\text{Zone active demand}} \times 100$

Zone reactive demand (MVAr) = Reactive power transfers into the 110kV measured at the 132/110kV transformers at Palmwoods and 275/110kV transformers inclusive of south of South Pine and east of Abermain + reactive power generation from 50MVAr shunt capacitor banks within this zone + reactive power transfer across Terranora Interconnector.

Zone active demand (MW) = Active power transfers into the 110kV measured at the 132/110kV transformers at Palmwoods and the 275/110kV transformers inclusive of south of South Pine and east of Abermain + active power transfer on Terranora Interconnector.

(7) The reactive to active demand percentage is bounded between 10 and 35.

Table D.5 Gold Coast grid section voltage stability equation

Measured variable	Coefficient
Constant term (intercept)	1,351
Moreton to Gold Coast demand ratio (1) (2)	-137.50
Number of Wivenhoe units on line [0 to 2]	17.7695
Number of Swanbank E units on line [0 to 1]	-20.0000
Active power transfer (MW) across Terranora Interconnector (3)	-0.9029
Reactive power transfer (MVAr) across Terranora Interconnector (3)	0.1126
Number of 200MVAr capacitor banks available (4)	14.3339
Number of 120MVAr capacitor banks available (5)	10.3989
Number of 50MVAr capacitor banks available (6)	4.9412
AEMO Constraint ID	**Q^NIL_GC**

Notes:

(1) Moreton to Gold Coast demand ratio $= \frac{\text{Moreton zone active demand}}{\text{Gold Coast zone active demand}} \times 100$

(2) The Moreton to Gold Coast demand ratio is bounded between 4.7 and 6.0.

(3) Positive transfer denotes northerly flow.

(4) There are currently 4 capacitor banks of nominal size 200MVAr which may be available within this area.

(5) There are currently 16 capacitor banks of nominal size 120MVAr which may be available within this area.

(6) There are currently 34 capacitor banks of nominal size 50MVAr which may be available within this area.

Appendix E – Indicative short circuit currents

Tables E.1 to E.3 show indicative maximum and minimum short circuit currents at Powerlink Queensland's substations.

Indicative maximum short circuit currents

Tables E.1 to E.3 show indicative maximum symmetrical three phase and single phase to ground short circuit currents in Powerlink's transmission network for summer 2017/18, 2018/19 and 2019/20.

These results include the short circuit contribution of some of the more significant embedded non-scheduled generators, however smaller embedded non-scheduled generators may have been excluded. As a result, short circuit currents may be higher than shown at some locations. Therefore, this information should be considered as an indicative guide to short circuit currents at each location and interested parties should consult Powerlink and/or the relevant Distribution Network Service Provider (DNSP) for more detailed information.

The maximum short circuit currents were calculated:

- using a system model, in which generators were represented as a voltage source of 110% of nominal voltage behind sub-transient reactance
- with all model shunt elements removed.

The short circuit currents shown in tables E.1 to E.3 are based on generation shown in Table 5.1 (together with any of the more significant embedded non-scheduled generators) and on the committed network development as at the end of each calendar year. The tables also show the rating of the lowest rated Powerlink owned plant at each location. No assessment has been made of the short circuit currents within networks owned by DNSPs or directly connected customers, nor has an assessment been made of the ability of their plant to withstand and/or interrupt the short circuit current.

The maximum short circuit currents presented in this appendix are based on all generating units online and an 'intact' network, that is, all network elements are assumed to be in-service. This assumption can result in short circuit currents appearing to be above plant rating at some locations. Where this is found, detailed assessments are made to determine if the contribution to the total short circuit current that flows through the plant exceeds its rating. If so, the network may be split to create 'normally-open' point as an operational measure to ensure that short circuit currents remain within the plant rating, until longer term solutions can be justified.

Indicative minimum short circuit currents

The connection of fluctuating load and power electronic connected systems (such as solar PV and static VAr compensators) should consider the minimum short circuit current at the prospective point of connection to ensure that there is no adverse impact on power quality and stability.

Tables E.1 to E.3 show indicative minimum symmetrical three phase short circuit currents at Powerlink's substations. These indicative minimum short circuit currents were calculated by analysing half hourly system normal snapshots over the period 1 April 2016 and 31 March 2017. The minimum of sub-transient, transient and synchronous short circuit currents over the year were compiled for each substation, with the individual outage of each significant network element.

Minimum system normal short circuit currents are also included, based on the same methodology, instead with all network elements in-service. These short circuit currents could be used to calculate connection capacity for proponents who would be willing to reduce capacity for specific network outages.

These minimum short circuit currents are indicative only, and are based on history. Short circuit currents can be lower for different generation dispatches and/or network elements out of service.

Table E.1 Indicative short circuit currents – northern Queensland – 2017/18 to 2019/20

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2017/18		2018/19		2019/20	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Alan Sherriff	132	40.0	4.2	3.8	12.2	12.8	12.7	13.2	12.7	13.2
Alligator Creek	132	25.0	3.1	1.8	4.5	5.9	4.5	5.9	4.5	5.9
Bollingbroke	132	40.0	2.0	1.9	2.4	1.9	2.4	1.9	2.4	1.9
Bowen North	132	40.0	2.0	0.5	2.2	2.4	2.2	2.5	2.2	2.5
Cairns (2T)	132	25.0	2.7	0.7	5.5	7.3	5.9	7.8	5.9	7.8
Cairns (3T)	132	25.0	2.7	0.7	5.5	7.3	5.9	7.8	5.9	7.8
Cairns (4T)	132	25.0	2.7	0.7	5.5	7.4	5.9	7.9	5.9	7.9
Cardwell	132	19.3	1.9	1.0	3.0	3.2	3.0	3.3	3.0	3.3
Chalumbin	275	31.5	1.6	1.2	3.8	4.0	4.2	4.4	4.2	4.4
Chalumbin	132	31.5	2.9	2.3	6.2	7.1	6.5	7.5	6.5	7.5
Clare South	132	40.0	3.4	2.8	7.7	7.9	7.9	8.0	7.9	8.0
Collinsville North	132	31.5	4.5	2.3	7.6	8.6	8.3	9.1	8.3	9.1
Coppabella	132	31.5	2.2	1.4	2.9	3.3	2.9	3.3	2.9	3.3
Dan Gleeson (1T)	132	31.5	4.1	3.6	11.6	12.2	12.1	12.6	12.1	12.6
Dan Gleeson (2T)	132	40.0	4.1	3.6	11.6	12.2	12.0	12.5	12.0	12.5
Edmonton	132	40.0	2.6	0.8	5.0	6.2	5.3	6.5	5.3	6.5
Eagle Downs	132	40.0	2.9	1.5	4.2	4.2	4.2	4.2	4.2	4.2
El Arish	132	40.0	2.0	1.0	3.1	3.9	3.2	4.0	3.2	4.0
Garbutt	132	40.0	3.9	1.9	10.2	10.3	10.5	10.4	10.5	10.4
Goonyella Riverside	132	40.0	3.4	2.9	5.3	5.0	5.4	5.1	5.4	5.1
Ingham South	132	31.5	1.9	1.0	3.2	3.1	3.2	3.1	3.2	3.1
Innisfail	132	40.0	1.9	1.2	2.8	3.4	2.9	3.5	2.9	3.5
Invicta	132	19.3	2.6	1.7	5.2	4.7	5.3	4.7	5.3	4.7
Kamerunga	132	15.3	2.3	0.6	4.3	5.2	4.5	5.4	4.5	5.4
Kareeya	132	40.0	2.6	2.1	5.4	6.0	5.6	6.3	5.6	6.3
Kemmis	132	31.5	3.9	1.6	5.8	6.4	5.8	6.4	5.8	6.4
King Creek	132	40.0	2.9	1.4	4.5	3.8	4.6	3.9	4.6	3.9
Mackay (2T)	132	10.9	3.4	2.9	4.7	5.4	4.7	5.4	4.7	5.4
Mackay (1T & 3T)	132	10.9	3.4	2.9	4.8	5.4	4.8	5.4	4.8	5.4
Mackay Ports	132	40.0	2.6	1.6	3.5	4.1	3.5	4.1	3.5	4.1
Mindi	132	40.0	3.3	3.1	4.4	3.6	4.4	3.6	4.4	3.6
Moranbah	132	10.9	3.8	3.1	6.6	8.0	6.7	8.1	6.7	8.1

Table E.1 Indicative short circuit currents – northern Queensland – 2017/18 to 2019/20 *(continued)*

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2017/18		2018/19		2019/20	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Moranbah South	132	31.5	3.2	2.6	5.0	4.8	5.0	4.8	5.0	4.8
Mt McLaren	132	31.5	1.5	1.4	2.0	2.1	2.0	2.1	2.0	2.1
Nebo	275	31.5	4.1	3.6	9.4	9.9	9.4	9.9	9.4	9.9
Nebo	132	15.3	6.9	6.1	12.8	14.8	12.8	14.8	12.8	14.8
Newlands	132	25.0	2.4	1.3	3.3	3.8	3.4	3.8	3.4	3.8
North Goonyella	132	20.0	2.8	1.0	4.1	3.5	4.1	3.6	4.1	3.6
Oonooie	132	31.5	2.3	1.5	3.1	3.7	3.1	3.7	3.1	3.7
Peak Downs	132	31.5	2.7	1.6	3.9	3.5	3.9	3.5	3.9	3.5
Pioneer Valley	132	31.5	4.1	3.5	7.0	7.8	7.0	7.8	7.0	7.8
Proserpine	132	40.0	2.3	1.5	2.6	3.2	2.7	3.3	2.7	3.3
Ross	275	31.5	2.6	2.3	7.2	8.3	7.7	8.6	7.7	8.6
Ross	132	31.5	4.7	4.2	15.6	18.0	16.7	19.0	16.7	19.0
Springlands	132	40.0	–	–	–	–	9.2	10.2	9.2	10.2
Stony Creek	132	40.0	2.5	1.2	3.4	3.4	3.5	3.5	3.5	3.5
Strathmore	275	31.5	3.2	2.8	7.9	8.4	8.2	8.7	8.2	8.7
Strathmore	132	40.0	4.8	2.2	8.4	9.7	9.2	10.5	9.2	10.5
Townsville East	132	40.0	4.0	1.5	11.8	11.8	12.2	12.0	12.2	12.0
Townsville South	132	21.9	4.3	3.9	15.5	19.0	16.1	19.7	16.1	19.7
Townsville PS	132	31.5	3.6	2.5	10.0	10.7	10.3	10.9	10.3	10.9
Tully	132	31.5	2.3	1.9	3.9	4.1	4.0	4.2	4.0	4.2
Turkinje	132	20.0	1.6	1.1	2.6	3.0	2.7	3.0	2.7	3.0
Walkamin	275	40.0	–	–	–	–	3.2	3.7	3.2	3.7
Wandoo	132	31.5	3.2	3.1	4.4	3.3	4.4	3.3	4.4	3.3
Woree (1T)	275	40.0	1.3	0.9	2.6	3.1	2.8	3.2	2.8	3.2
Woree (2T)	275	40.0	1.3	0.9	2.6	3.0	2.9	3.4	2.9	3.4
Woree	132	40.0	2.8	2.3	5.7	7.8	6.1	8.4	6.1	8.4
Wotonga	132	40.0	3.5	1.6	5.5	6.5	5.5	6.5	5.5	6.5
Yabulu South	132	40.0	4.1	3.7	11.7	11.4	12.1	11.7	12.1	11.7

Table E.2 Indicative short circuit currents – central Queensland – 2017/18 to 2019/20

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2017/18		2018/19		2019/20	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Blackwater	132	10.9	3.9	3.0	5.7	6.9	5.2	6.5	5.2	6.5
Bluff	132	40.0	2.5	2.1	3.4	4.2	3.3	4.1	3.3	4.1
Bouldercombe	275	31.5	6.9	6.3	19.7	19.2	19.8	19.5	19.8	19.5
Bouldercombe	132	21.8	9.2	7.1	11.5	13.5	14.5	16.9	14.5	16.9
Broadsound	275	31.5	5.0	4.3	11.3	8.8	11.2	8.6	11.2	8.6
Callemondah	132	31.5	11.0	5.6	24.1	26.4	22.4	24.9	22.4	24.9
Callide A	132	11.0	5.2	1.0	10.2	10.5	–	–	–	–
Calliope River	275	40.0	7.5	6.8	21.0	23.8	20.8	23.7	20.8	23.7
Calliope River	132	40.0	11.7	10.4	27.0	31.9	25.1	30.2	25.1	30.2
Calvale	275	31.5	7.4	6.5	23.7	26.0	23.3	25.8	23.3	25.8
Calvale (1T)	132	31.5	5.3	1.0	10.2	10.6	8.7	9.6	8.7	9.6
Calvale (2T)	132	31.5	–	–	–	–	8.4	9.2	8.4	9.2
Dingo	132	31.5	2.1	1.1	2.7	2.9	2.7	2.9	2.7	2.9
Duaringa	132	40.0	1.7	1.1	2.1	2.8	1.3	1.8	1.3	1.8
Dysart	132	10.9	3.1	1.8	4.4	5.1	4.4	5.1	4.4	5.1
Egans Hill	132	25.0	6.0	1.6	7.3	7.4	8.3	8.2	8.3	8.2
Gladstone PS	275	40.0	7.2	6.6	19.5	21.7	19.4	21.6	19.4	21.6
Gladstone PS	132	40.0	10.7	9.6	23.4	26.3	22.0	25.2	22.0	25.2
Gladstone South	132	40.0	9.1	7.4	18.7	19.1	16.4	17.3	16.4	17.3
Grantleigh	132	31.5	2.2	2.1	2.6	2.7	2.7	2.8	2.7	2.8
Gregory	132	31.5	5.7	4.7	8.8	10.1	8.5	9.9	8.5	9.9
Larcom Creek	275	40.0	6.5	3.0	15.5	15.3	15.4	15.3	15.4	15.3
Larcom Creek	132	40.0	6.9	3.8	12.3	13.8	12.3	13.8	12.3	13.8
Lilyvale	275	31.5	3.3	2.5	5.6	5.6	5.5	5.6	5.5	5.6
Lilyvale	132	25.0	5.9	4.8	9.2	10.9	8.9	10.6	8.9	10.6
Moura	132	12.3	2.8	1.1	4.0	4.3	3.9	4.2	3.9	4.2
Norwich Park	132	31.5	2.7	1.2	3.5	2.6	3.5	2.6	3.5	2.6
Pandoin	132	40.0	5.3	1.3	6.2	5.8	7.0	6.3	7.0	6.3
Raglan	275	40.0	5.8	3.7	11.9	10.4	11.9	10.4	11.9	10.4
Rockhampton (1T)	132	10.9	4.9	1.8	5.8	5.9	6.5	6.4	6.5	6.4
Rockhampton (5T)	132	10.9	4.7	1.8	5.6	5.8	6.3	6.2	6.3	6.2
Rocklands	132	31.5	5.6	4.8	6.8	6.1	7.7	6.6	7.7	6.6

Table E.2 Indicative short circuit currents – central Queensland – 2017/18 to 2019/20 *(continued)*

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2017/18		2018/19		2019/20	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Stanwell	275	31.5	7.1	6.5	22.4	24.0	22.4	24.1	22.4	24.1
Stanwell	132	31.5	4.6	4.0	5.4	6.0	6.0	6.5	6.0	6.5
Wurdong	275	31.5	7.1	5.7	17.0	16.8	16.8	16.7	16.8	16.7
Wycarbah	132	40.0	3.7	3.3	4.2	5.1	4.5	5.4	4.5	5.4
Yarwun	132	40.0	6.8	4.2	12.9	14.9	12.9	14.9	12.9	14.9

Table E.3 Indicative short circuit currents – southern Queensland – 2017/18 to 2019/20

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2017/18		2018/19		2019/20	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Abermain	275	40.0	6.7	5.7	18.0	18.6	18.0	18.6	18.0	18.6
Abermain	110	31.5	12.2	10.0	21.3	25.2	21.4	25.2	21.4	25.2
Algester	110	40.0	12.4	11.1	21.5	21.2	21.5	21.2	21.5	21.2
Ashgrove West	110	26.3	11.5	9.1	19.0	20.0	19.1	20.0	19.1	20.0
Belmont	275	31.5	6.6	6.2	16.7	18.5	16.8	18.6	16.8	18.6
Belmont	110	37.4	14.7	14.0	29.7	37.0	29.7	37.0	29.7	37.0
Blackstone	275	40.0	7.0	6.5	20.9	23.2	21.0	23.2	21.0	23.2
Blackstone	110	40.0	13.4	12.5	25.2	28.9	25.3	29.0	25.3	29.0
Blackwall	275	37.0	7.2	6.7	22.0	23.9	22.1	24.0	22.1	24.0
Blythdale	132	40.0	3.3	2.4	4.2	5.2	4.2	5.2	4.2	5.2
Braemar	330	50.0	5.9	5.5	23.0	25.1	23.4	25.3	23.4	25.3
Braemar (East)	275	40.0	7.5	4.8	26.4	30.8	26.7	31.0	26.7	31.0
Braemar (West)	275	40.0	7.2	4.8	26.3	29.3	27.1	29.7	27.1	29.7
Bulli Creek	330	50.0	6.2	5.8	18.1	14.3	18.2	14.3	18.2	14.3
Bulli Creek	132	40.0	3.1	3.0	3.8	4.3	3.8	4.3	3.8	4.3
Bundamba	110	40.0	10.6	7.6	17.2	16.6	17.2	16.6	17.2	16.6
Chinchilla	132	25.0	5.3	4.2	7.9	7.8	8.0	7.8	8.0	7.8
Clifford Creek	132	40.0	4.3	3.5	5.7	5.2	5.7	5.2	5.7	5.2
Columboola	275	40.0	5.3	4.4	12.2	11.6	12.4	11.7	12.4	11.7
Columboola	132	25.0	7.7	6.0	16.1	18.2	16.1	18.2	16.1	18.2
Condabri North	132	40.0	6.9	5.6	13.1	12.1	13.1	12.1	13.1	12.1
Condabri Central	132	40.0	5.5	4.6	8.9	6.6	8.9	6.6	8.9	6.6
Condabri South	132	40.0	4.5	3.7	6.5	4.4	6.5	4.4	6.5	4.4
Dinoun South	132	40.0	4.7	3.8	6.5	6.8	6.5	6.8	6.5	6.8
Eurombah (1T)	275	40.0	2.9	1.2	4.3	4.5	4.3	4.5	4.3	4.5
Eurombah (2T)	275	40.0	2.9	1.2	4.3	4.5	4.3	4.5	4.3	4.5
Eurombah	132	40.0	4.9	3.6	6.8	8.4	6.9	8.4	6.9	8.4
Fairview	132	40.0	3.2	2.6	4.0	5.1	4.0	5.1	4.0	5.1
Fairview South	132	40.0	4.0	3.1	5.2	6.6	5.2	6.6	5.2	6.6
Gin Gin	275	14.5	6.1	5.6	10.9	10.1	11.0	10.1	11.0	10.1
Gin Gin	132	20.0	8.2	6.2	12.8	13.9	12.9	13.9	12.9	13.9
Goodna	275	40.0	6.5	5.2	16.0	16.0	16.1	16.0	16.1	16.0

Table E.3 Indicative short circuit currents – southern Queensland – 2017/18 to 2019/20 *(continued)*

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2017/18		2018/19		2019/20	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Goodna	110	40.0	13.5	12.1	25.3	27.4	25.3	27.5	25.3	27.5
Greenbank	275	40.0	6.9	6.5	20.2	22.4	20.3	22.4	20.3	22.4
Halys	275	50.0	8.0	7.2	31.3	26.0	31.7	26.1	31.7	26.1
Kumbarilla Park (1T)	275	40.0	6.3	1.7	16.5	15.9	16.6	16.0	16.6	16.0
Kumbarilla Park (2T)	275	40.0	6.3	1.7	16.5	15.9	16.6	16.0	16.6	16.0
Kumbarilla Park	132	40.0	8.6	5.7	13.2	15.2	13.2	15.2	13.2	15.2
Loganlea	275	40.0	6.3	5.6	14.8	15.4	14.8	15.4	14.8	15.4
Loganlea	110	31.5	13.1	12.1	22.8	27.4	22.8	27.4	22.8	27.4
Middle Ridge (4T)	330	50.0	5.3	3.2	12.5	12.2	12.6	12.2	12.6	12.2
Middle Ridge (5T)	330	50.0	5.3	3.2	12.9	12.6	12.9	12.6	12.9	12.6
Middle Ridge	275	31.5	6.7	6.3	17.9	18.1	17.9	18.1	17.9	18.1
Middle Ridge	110	18.3	10.7	9.1	20.3	24.1	20.4	24.3	20.4	24.3
Millmerran	330	40.0	5.9	5.4	18.3	19.6	18.3	19.7	18.3	19.7
Molendinar (1T)	275	40.0	4.8	2.1	8.2	8.1	8.2	8.1	8.2	8.1
Molendinar (2T)	275	40.0	4.7	2.1	8.2	8.1	8.2	8.1	8.2	8.1
Molendinar	110	40.0	11.6	10.2	20.0	25.3	19.2	24.4	19.2	24.4
Mt England	275	31.5	7.1	6.6	22.4	22.7	22.5	22.8	22.5	22.8
Mudgeeraba	275	31.5	5.1	4.2	9.4	9.4	9.2	8.6	9.2	8.6
Mudgeeraba	110	25.0	10.9	10.0	18.7	22.8	17.3	21.0	17.3	21.0
Murarrie (2T)	275	40.0	6.0	2.5	13.0	13.5	13.0	13.5	13.0	13.5
Murarrie (3T)	275	40.0	6.0	2.5	13.0	13.5	13.0	13.5	13.0	13.5
Murarrie	110	40.0	13.5	12.8	24.2	29.2	24.3	29.2	24.3	29.2
Oakey GT PS	110	31.5	5.1	1.2	10.8	12.0	10.9	12.1	10.9	12.1
Oakey	110	40.0	4.9	1.3	10.1	10.0	10.2	10.1	10.2	10.1
Orana	275	40.0	5.8	3.4	14.6	13.6	14.9	13.7	14.9	13.7
Palmwoods	275	31.5	5.2	3.4	8.4	8.8	8.5	8.8	8.5	8.8
Palmwoods	132	21.9	9.1	6.9	13.0	15.5	13.0	15.6	13.0	15.6
Palmwoods (7T)	110	40.0	5.8	2.7	7.2	7.5	7.2	7.5	7.2	7.5
Palmwoods (8T)	110	40.0	5.8	2.7	7.2	7.5	7.2	7.5	7.2	7.5
Redbank Plains	110	31.5	12.1	9.2	21.3	20.8	21.3	20.8	21.3	20.8
Richlands	110	40.0	12.5	10.8	22.0	22.7	22.0	22.7	22.0	22.7
Rocklea (1T)	275	31.5	6.0	2.4	13.1	12.3	13.1	12.3	13.1	12.3

Table E.3 Indicative short circuit currents – southern Queensland – 2017/18 to 2019/20 *(continued)*

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2017/18		2018/19		2019/20	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Rocklea (2T)	275	31.5	5.1	2.4	8.7	8.4	8.7	8.4	8.7	8.4
Rocklea	110	31.5	13.5	12.2	24.8	28.7	24.9	28.7	24.9	28.7
Runcorn	110	40.0	11.6	8.2	19.3	19.6	19.4	19.6	19.4	19.6
South Pine	275	31.5	7.1	6.7	18.5	21.1	18.6	21.2	18.6	21.2
South Pine (East)	110	40.0	12.9	11.3	21.4	27.5	21.5	27.5	21.5	27.5
South Pine (West)	110	40.0	12.2	9.9	20.3	23.5	20.4	23.5	20.4	23.5
Sumner	110	40.0	12.0	8.9	20.6	20.2	20.6	20.3	20.6	20.3
Swanbank E	275	40.0	6.9	5.8	20.6	22.7	20.7	22.8	20.7	22.8
Tangkam	110	31.5	5.9	4.0	12.8	12.0	12.9	12.1	12.9	12.1
Tarong (1)	275	31.5	8.0	7.3	32.9	34.5	33.2	34.7	33.2	34.7
Tarong (1T)	132	25.0	4.7	1.1	5.8	6.0	5.8	6.0	5.8	6.0
Tarong (4T)	132	25.0	4.7	1.1	5.8	6.0	5.8	6.0	5.8	6.0
Tarong	66	40.0	11.9	7.2	15.0	16.2	15.0	16.2	15.0	16.2
Teebar Creek	275	40.0	4.9	3.3	7.3	7.2	7.4	7.3	7.4	7.3
Teebar Creek	132	40.0	7.7	6.1	10.1	11.2	10.4	11.4	10.4	11.4
Tennyson	110	40.0	10.4	1.7	16.2	16.4	16.2	16.4	16.2	16.4
Upper Kedron	110	40.0	12.3	10.9	21.1	18.7	21.2	18.7	21.2	18.7
Wandoan South	275	40.0	4.0	3.2	7.0	7.7	7.1	7.7	7.1	7.7
Wandoan South	132	40.0	5.4	4.0	8.6	11.0	8.6	11.0	8.6	11.0
West Darra	110	40.0	13.3	12.4	24.8	23.8	24.8	23.8	24.8	23.8
Western Downs	275	40.0	6.8	5.5	24.1	24.2	25.1	24.5	25.1	24.5
Woolooga	275	31.5	5.8	5.0	9.7	10.8	9.8	10.9	9.8	10.9
Woolooga	132	20.0	9.4	7.8	13.0	15.5	13.1	15.6	13.1	15.6
Yuleba North	275	40.0	3.5	2.9	5.7	6.3	5.8	6.4	5.8	6.4
Yuleba North	132	40.0	5.4	4.2	7.7	9.3	7.7	9.4	7.7	9.4

Note:

(1) The lowest rated plant at this location is required to withstand and/or interrupt a short circuit current which is less than the maximum short circuit current and below the plant rating.

Appendix F – Abbreviations

AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APR	Annual Planning Report
CAA	Connection and Access Agreement
CQ	Central Queensland
CSG	Coal seam gas
CSM	Coal seam methane
DNSP	Distribution Network Service Provider
EII	Energy Infrastructure Investments
ESOO	Electricity Statement of Opportunity
FNQ	Far North Queensland
GT	Gas Turbine
GWh	Gigawatt hour
JPB	Jurisdictional Planning Body
kA	Kiloampere
kV	Kilovolt
MJ	Megajoules
MVA	Megavolt Ampere
MVAr	Megavolt Ampere reactive
MW	Megawatt
MWh	Megawatt hour
NEFR	National Electricity Forecasting Report
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NER	National Electricity Rules
NNESR	Non-network Engagement Stakeholder Register
NSCAS	Network Support and Control Ancillary Services
NTNDP	National Transmission Network Development Plan
NSW	New South Wales
NQ	North Queensland
NWD	Non-weather dependent
PoE	Probability of exceedance
PS	Power Station
PV	Photovoltaic
QAL	Queensland Alumina Limited
QER	Queensland Energy Regulator
QGC	Queensland Gas Company
QNI	Queensland/New South Wales Interconnector transmission line
REZ	Renewable Energy Zone
RIT-T	Regulatory Investment Test for Transmission
RTA	Rio Tino Aluminium
SCR	Short Circuit Ratio
SEQ	South East Queensland
SQ	South Queensland
STATCOM	Static Synchronous Compensator
SVC	Static VAr Compensator
SWQ	South West Queensland
SynCon	Synchronous Condensor
TAPR	Transmission Annual Planning Report
TNSP	Transmission Network Service Provider
VRE	Variable renewable electricity
WD	Weather dependent

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