Appendices

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 peak demand

Connection point	Voltage (kV)	Zone	2016/17		2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25		2025/26(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	27	14	27	14	28	14	27	14	28	14	28	14	29	14	28	14	29	14	29	15
Aligator Creek (Louisa Creek)	132	N	57	17	56	17	56	17	54	16	54	16	54	16	54	16	53	16	52	16	52	16
Alligator Creek	33	N	44	16	43	16	43	16	43	16	43	16	42	16	43	16	42	16	42	16	42	16
Biloela	66	CW	35	7	35	7	35	7	35	6	35	7	36	7	36	7	36	7	36	7	35	7
Blackwater	132	CW	30	19	32	20	32	20	31	20	31	20	31	19	31	19	30	19	30	19	30	19
Blackwater	66	CW	120	14	120	14	118	14	116	13	126	14	138	16	140	16	137	16	136	16	135	15
Bowen North	66	R	22	8	23	9	23	9	24	9	24	9	24	9	24	9	23	9	24	9	24	9
Bulli Creek (Waggamba)	132	B	18	3	18	3	18	3	17	3	17	3	17	3	17	3	17	3	17	3	17	3
Cairns	22	FN	49	0	49	0	48	0	47	0	47	0	47	0	47	0	46	0	45	0	45	0
Cairns City	132	FN	61	32	61	32	60	32	59	31	58	31	58	30	58	30	56	30	56	29	56	29
Calliope River	132	G	38	20	38	20	43	23	41	21	41	21	40	21	40	21	40	20	39	20	39	20
Cardwell	22	R	6	4	6	4	6	4	6	4	6	4	6	4	6	4	6	4	6	4	6	4
Chinchilla	132	SW	22	11	22	11	22	11	22	11	22	11	23	11	23	11	23	11	23	11	23	11
Clare South	66	R	73	23	73	23	72	23	71	23	71	23	70	22	70	23	69	22	69	22	68	22
Collinsville	33	N	18	9	18	9	18	10	22	11	22	12	22	12	23	12	23	12	23	12	23	12
Columboola	132	SW	68	9	68	9	71	9	70	9	71	10	73	10	73	10	72	10	72	10	72	10
Dan Gleeson	66	R	112	46	107	43	107	43	105	42	105	42	105	44	106	44	104	43	104	43	104	43
Dysart	66	CW	75	13	74	13	74	12	72	12	72	12	72	12	72	12	70	12	70	12	69	12
Edmonton	22	FN	45	10	45	10	46	10	45	10	46	10	46	10	47	10	46	10	47	10	47	10
Egans Hill	66	CW	55	9	55	9	55	9	55	9	55	9	55	9	55	9	55	8	55	8	55	8
El Arish	22	FN	5	1	5	1	5	1	5	1	5	1	5	1	5	1	5	1	5	1	5	1
Garbutt	66	R	116	47	111	45	110	45	109	44	109	44	109	45	109	45	108	45	108	45	108	44

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

Connection point	Voltage (kV)	Zone	2016/17		2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25		2025/26(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	154	19	153	19	152	19	149	19	148	19	147	18	147	18	145	18	144	18	143	18
Gladstone South	66	G	76	28	76	29	77	29	78	29	79	30	80	30	81	31	81	30	82	31	82	31
Ingham	66	R	19	5	18	5	18	5	18	5	18	5	18	4	18	4	17	4	17	4	17	4
Innisfail	22	FN	27	14	27	14	27	14	26	13	26	13	26	13	26	13	25	13	25	13	25	13
Kamerunga	22	FN	64	22	64	22	65	22	64	22	64	22	69	24	73	26	73	25	73	25	73	26
Lilyvale (Barcaldine & Clermont)	132	CW	44	7	44	7	44	7	43	7	43	7	43	7	43	7	43	7	43	7	43	7
Lilyvale	66	CW	155	67	155	67	154	67	158	68	158	68	157	68	157	68	155	67	154	67	153	66
Mackay	33	N	95	71	94	71	94	70	92	69	92	69	91	68	92	68	90	67	89	67	89	67
Middle Ridge	110	SW	197	28	197	28	196	28	192	27	192	27	191	27	192	27	189	27	189	27	188	27
Middle Ridge (Postmans Ridge)	110	M	23	10	23	10	23	10	23	10	23	10	23	10	23	10	22	10	22	10	22	10
Moranbah (Broadlea)	132	N	48	18	48	18	48	18	47	17	54	20	57	21	58	21	57	21	57	21	56	21
Moranbah	66 and 11	N	112	34	130	39	129	39	126	38	126	38	135	41	146	44	143	43	142	43	141	43
Moura	66	CW	62	20	62	20	61	20	61	20	61	20	61	20	61	20	60	20	60	20	60	19
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	37	12	36	12	41	14	40	13	40	13	40	13	40	13	39	13	39	13	38	13
Oakey	110	SW	27	6	27	6	27	6	27	6	27	6	27	6	27	6	27	6	27	6	27	6
Pandoin	66	CW	45	7	45	7	45	7	44	7	45	7	45	7	45	7	44	7	44	7	44	7
Pioneer Valley	66	N	59	27	59	27	58	27	57	26	57	26	57	26	57	26	55	26	55	25	55	25
Proserpine	66	N	57	20	57	20	57	20	56	19	61	21	65	23	65	23	64	22	64	22	63	22

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

Connection point	Voltage (kV)	Zone	2016/17		2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25		2025/26(1)	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Rockhampton	66	CW	99	16	100	16	99	16	98	15	98	16	98	15	99	16	98	15	98	15	98	15
Ross (Kidston, Milchester and Georgetown)	132	R	40	15	40	15	40	15	40	14	40	15	40	15	40	15	40	14	40	14	40	14
Stoney Creek	132	N	3	1	3	1	3	1	3	1	3	1	3	1	3	1	2	1	2	1	2	1
Tangkam	110	SW	31	9	31	9	32	10	32	10	32	10	32	10	33	10	32	10	33	10	33	10
Tarong	66	SW	42	17	42	17	41	17	41	17	41	17	41	16	41	17	40	16	40	16	40	16
Teebar Creek (Isis and Maryborough)	132	WB	121	39	121	39	121	39	119	38	119	39	119	38	120	39	118	38	118	38	118	38
Townsville East	66	R	41	17	39	16	39	16	39	16	39	16	39	16	39	16	38	16	38	16	38	16
Townsville South	66	R	110	45	105	42	105	42	103	41	103	41	103	43	104	43	102	42	102	42	102	42
Tully	22	R	15	7	15	7	15	7	14	7	14	7	14	7	14	7	14	7	14	7	14	7
Turkinje (Craiglie and Lakeland)	132	FN	23	7	23	7	23	7	22	7	22	7	22	7	22	7	22	7	22	7	22	7
Turkinje	66	FN	59	16	63	17	62	17	61	16	64	17	63	17	63	17	62	17	62	17	61	16
Woolooga (Kilkivan)	132	WB	32	4	32	4	31	4	31	4	31	4	30	4	30	4	30	4	30	4	30	4
Woree (Cairns North)	132	FN	46	22	48	22	49	23	49	23	51	24	52	24	53	25	54	25	55	26	56	26
Yarwun (Boat Creek)	132	G	43	27	43	27	42	26	41	26	41	26	41	25	40	25	40	25	39	25	39	24
Hail Creek and King Creek	Various	N	47	11	47	11	47	11	46	11	45	11	45	10	45	10	44	10	44	10	43	10

Note:

(1) Connection point loads for summer 2025/26 have been extrapolated.

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

Connection point	Voltage (kV)	Zone	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
Alan Sherriff	132	R	18	9	18	9	18	9	18	9	17	9	17	9	17	9	18	9	18	9	17	9
Alligator Creek (Louisa Creek)	132	N	51	17	51	17	51	17	51	17	49	16	49	16	49	16	49	16	48	16	48	16
Alligator Creek	33	N	20	8	20	8	20	8	20	8	20	7	20	7	20	7	20	7	19	7	19	7
Biloela	66	CW	29	4	29	4	29	4	29	4	29	4	30	4	30	4	30	4	30	4	30	4
Blackwater	132	CW	29	21	32	23	31	23	31	23	30	22	30	22	30	22	30	22	30	22	30	21
Blackwater	66	CW	99	14	99	14	98	14	98	14	104	15	115	16	116	16	117	17	115	16	114	16
Bowen North	66	R	26	10	26	11	27	11	27	11	30	12	30	12	30	12	30	12	29	12	30	12
Bulli Creek (Waggamba)	132	B	21	11	21	11	21	11	21	11	21	11	21	11	21	11	22	11	21	11	21	11
Cairns	22	FN	39	5	39	5	39	5	38	5	37	5	37	5	37	5	37	5	37	5	36	5
Cairns City	132	FN	42	23	42	23	42	23	41	23	40	22	40	22	40	22	40	22	39	22	39	22
Calliope River	132	G	32	16	32	16	38	19	38	19	35	18	35	18	35	18	35	18	34	18	34	17
Cardwell	22	R	4	3	4	3	4	3	4	3	4	3	4	3	4	3	4	3	4	3	4	3
Chinchilla	132	SW	19	5	19	5	18	5	18	5	18	5	18	4	18	4	18	4	17	4	17	4
Clare South	66	R	51	13	44	12	44	12	44	12	43	11	43	11	42	11	43	11	42	11	42	11
Collinsville	33	N	15	6	15	6	15	6	18	8	18	8	18	8	18	8	18	8	18	8	17	8
Columboola	132	SW	75	16	76	16	76	16	79	16	79	16	80	17	80	17	81	17	80	17	79	16
Dan Gleeson	66	R	91	32	92	32	85	28	85	28	83	27	83	27	84	27	85	28	84	28	84	28
Dysart	66	CW	40	7	60	10	60	10	59	10	58	10	58	10	57	10	58	10	57	10	56	10
Edmonton	22	FN	31	6	31	6	31	6	31	6	30	6	30	6	30	6	30	6	29	6	29	6
Egans Hill	66	CW	43	11	44	11	44	11	44	11	43	10	43	10	43	10	44	11	43	10	43	10
El Arish	22	FN	4	0	4	0	4	0	4	0	4	0	4	0	4	0	4	0	4	0	4	0
Garbutt	66	R	87	30	88	31	81	27	82	27	80	26	80	26	80	26	81	27	81	26	81	26

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

Connection point	Voltage (kV)	Zone	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
Gin Gin	132	WB	116	14	116	14	115	14	115	14	112	14	112	14	111	14	112	14	111	14	110	14
Gladstone South	66	G	63	21	63	21	63	21	63	21	63	21	63	21	64	21	64	22	64	22	64	22
Ingham	66	R	21	4	21	4	21	4	21	4	20	4	20	4	20	4	20	4	20	4	20	3
Innisfail	22	FN	25	13	25	13	25	13	25	13	24	12	24	12	24	12	24	12	24	12	24	12
Kamerunga	22	FN	43	13	43	13	42	13	42	13	41	12	44	13	47	14	47	14	47	14	46	14
Lilyvale Barcaldine and Clermont)	132	CW	37	2	37	2	37	2	37	2	36	2	36	2	36	2	36	2	36	2	35	2
Lilyvale	66	CW	133	56	139	58	138	57	138	58	140	58	139	58	139	58	139	58	137	57	136	57
Mackay	33	N	72	58	72	58	72	57	71	57	70	56	69	56	69	55	69	56	69	55	68	54
Middle Ridge	110	SW	198	17	198	17	197	17	197	17	192	17	192	17	192	17	193	17	190	17	189	17
Middle Ridge (Postmans Ridge)	110	M	51	16	51	16	51	16	51	16	50	16	50	16	50	16	51	16	50	16	50	16
Moranbah (Broadlea)	132	N	37	14	38	14	38	14	38	14	42	15	44	16	46	17	46	17	45	17	45	17
Moranbah	66 and 11	N	94	27	94	27	108	31	108	31	105	30	115	33	124	36	125	36	123	35	122	35
Moura	66	CW	51	16	51	16	51	16	51	16	51	16	51	16	51	16	51	16	51	16	51	16
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	36	12	36	12	41	13	40	13	39	13	39	13	39	13	39	13	39	13	38	13
Oakey	110	SW	21	3	21	3	21	3	21	3	20	3	20	3	20	3	20	3	20	3	20	3
Pandoin	66	CW	33	8	33	8	33	8	33	8	32	8	32	8	33	8	33	8	33	8	33	8
Pioneer Valley	66	N	50	21	50	21	50	21	50	21	49	21	49	21	49	21	49	21	49	21	49	20
Proserpine	66	N	35	13	35	13	35	13	35	13	39	14	43	16	43	16	43	16	43	16	43	16

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

Connection point	Voltage (kV)	Zone	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
Rockhampton	66	CW	69	17	70	17	70	17	70	17	68	17	69	17	69	17	70	17	69	17	69	17
Ross (Kidston, Milchester and Georgetown)	132	R	30	10	30	10	30	10	30	10	30	10	30	10	30	10	31	10	30	10	30	10
Stoney Creek	132	N	3	1	3	1	3	1	3	1	2	1	2	1	2	1	2	1	2	1	2	1
Tangkam	110	SW	30	8	30	8	30	8	30	8	30	8	30	8	30	8	31	8	30	8	30	8
Tarong	66	SW	39	12	39	12	38	12	38	12	37	12	37	12	37	12	37	12	37	12	37	12
Teebar Creek (Isis and Maryborough)	132	WB	111	15	111	15	110	15	110	15	107	14	107	14	106	14	107	14	106	14	105	14
Townsville East	66	R	41	14	41	14	38	12	38	12	37	12	37	12	37	12	38	12	37	12	38	12
Townsville South	66	R	83	29	84	29	78	26	78	26	76	25	76	25	76	25	77	25	77	25	77	25
Tully	22	R	11	5	11	5	11	5	11	5	11	5	11	5	11	5	11	5	11	4	11	4
Turkinje (Craiglie and Lakeland)	132	FN	19	6	19	6	19	6	19	6	19	6	19	6	18	6	19	6	18	6	18	6
Turkinje	66	FN	55	13	55	13	59	14	59	14	57	13	60	14	60	14	60	14	59	14	59	14
Woolooga (Kilkivan)	132	WB	29	5	29	5	28	5	28	5	28	5	27	5	27	5	27	5	27	5	27	5
Woree (Cairns North)	132	FN	35	6	36	7	38	7	39	7	39	7	40	7	41	7	43	8	43	8	44	8
Yarwun (Boat Creek)	132	G	41	22	41	22	41	22	40	22	39	21	39	21	39	21	39	21	38	21	38	21
Hail Creek and King Creek	Various	N	46	9	46	9	45	9	45	9	44	9	44	9	43	9	44	9	43	9	42	9

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

Connection point	Voltage (kV)	Zone	2016/17		2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25		2025/26	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Abermain	110	M	54	18	55	19	55	19	55	19	56	19	57	19	57	19	58	19	58	20	59	20
Abermain	33	M	88	15	90	15	91	15	94	16	94	16	95	16	96	16	98	16	99	16	100	17
Algester	33	M	66	17	67	17	67	17	67	17	67	17	67	17	68	17	68	17	68	17	68	17
Ashgrove West	110	M	113	10	116	11	118	11	119	11	121	11	123	11	125	12	127	12	129	12	131	12
Ashgrove West	33	M	73	6	73	6	73	6	73	6	73	6	73	6	74	6	74	6	74	6	74	6
Belmont	110	M	414	264	426	272	431	275	434	277	435	278	438	280	444	284	451	288	457	292	462	295
Blackstone (Raceview)	110	M	89	14	91	14	93	14	93	14	94	14	95	14	95	15	96	15	82	12	82	13
Bundamba	110	M	35	23	36	23	36	23	36	23	36	23	36	23	36	23	37	24	37	24	37	24
Goodna	33	M	108	13	113	14	116	14	117	14	120	15	110	14	112	14	115	14	117	14	119	15
Loganlea	110	M	308	128	313	131	315	131	315	131	322	134	326	136	329	137	332	138	335	139	337	141
Loganlea	33	M	106	19	107	20	107	19	106	19	107	19	107	20	108	20	108	20	109	20	109	20
Middle Ridge (Postmans Ridge and Gatton)	110	M	140	19	142	19	143	20	143	20	144	20	144	20	145	20	146	20	146	20	147	20
Molendinar	110	GC	464	64	473	66	478	67	476	66	480	67	482	67	486	68	491	68	494	69	497	69
Mudgeeraba	110	GC	334	92	339	93	337	93	336	92	339	93	339	93	341	94	343	94	344	94	345	95
Mudgeeraba	33	GC	20	8	21	8	21	8	20	8	21	8	21	8	21	8	21	8	21	8	21	8
Murarrie	110	M	406	90	415	92	418	93	421	93	427	94	431	95	438	97	447	99	455	101	463	102
Palmwoods	110 & 132	M	365	166	374	170	375	171	378	172	386	176	393	179	403	184	411	187	413	188	415	189
Redbank Plains	11	M	20	7	21	7	21	7	22	7	22	8	23	8	23	8	24	8	24	8	25	9
Richlands	33	M	114	31	116	32	116	31	115	31	116	32	116	32	117	32	118	32	118	32	118	32
Rocklea	110	M	165	68	165	68	165	68	166	68	179	73	180	74	181	75	183	75	184	76	185	76

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

Connection point	Voltage (kV)	Zone	2016/17		2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25		2025/26	
			MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr	MW	MVAr
Runcorn	33	M	61	8	64	9	65	9	65	9	65	9	65	9	66	9	66	9	66	9	67	9
South Pine	110	M	896	191	911	194	910	194	911	194	921	196	926	197	933	199	942	201	948	202	954	203
Sumner	110	M	36	17	36	17	36	17	36	17	36	17	36	17	36	17	36	17	36	17	37	17
Tennyson	33	M	172	26	175	26	174	26	174	26	175	26	176	26	177	26	178	26	179	27	180	27
Wecker Road	33	M	128	20	130	20	132	20	132	21	134	21	134	21	135	21	136	21	136	21	137	21
Woolooga (Gympie)	132	M	171	16	173	16	172	16	172	16	174	16	174	17	175	17	176	17	177	17	178	17

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

Connection point	Voltage (kV)	Zone	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
Abermain	110	M	31	12	31	12	32	12	32	12	32	12	33	13	33	13	33	13	33	13	34	13
Abermain	33	M	64	5	65	5	67	6	67	6	69	6	70	6	71	6	72	6	73	6	74	6
Algester	33	M	54	30	54	30	55	30	55	30	54	30	55	30	55	30	55	30	55	30	56	31
Ashgrove West	110	M	81	11	86	11	89	12	90	12	91	12	93	12	94	12	95	12	97	13	99	13
Ashgrove West	33	M	70	8	70	8	71	8	71	8	70	8	71	8	71	8	71	8	71	8	72	8
Belmont	110	M	282	49	285	49	296	51	299	52	300	52	301	52	301	52	303	52	307	53	313	54
Blackstone (Raceview)	110	M	62	13	62	13	64	13	66	14	66	14	67	14	67	14	67	14	68	14	55	11
Bundamba	110	M	29	16	29	16	30	17	30	17	29	16	30	17	30	17	30	17	30	17	30	17
Goodna	33	M	82	7	87	8	92	8	94	9	95	9	98	9	90	8	91	8	94	9	96	9
Loganlea	110	M	213	65	213	65	220	67	221	67	222	68	228	69	229	70	230	70	232	71	235	72
Loganlea	33	M	74	11	74	11	75	11	75	11	74	11	75	11	75	11	75	11	75	11	76	12
Middle Ridge (Postmans Ridge and Gatton)	110	M	111	13	112	13	114	13	114	13	114	13	115	13	115	13	115	13	116	13	117	14
Molendinar	110	GC	344	26	347	27	357	27	359	28	356	27	362	28	362	28	363	28	366	28	371	28
Mudgeeraba	110	GC	267	74	267	74	273	75	271	75	269	74	273	75	272	75	272	75	273	75	276	76
Mudgeeraba	33	GC	18	6	18	6	19	6	18	6	18	6	19	6	19	6	19	6	19	7	19	7
Murarrie	110	M	345	73	347	74	356	76	358	76	359	76	364	77	368	78	374	79	381	81	389	83
Palmwoods	110 & 132	M	300	122	311	126	322	130	322	131	324	131	334	135	340	138	347	141	355	144	359	145
Redbank Plains	11	M	15	3	15	4	16	4	16	4	16	4	16	4	17	4	17	4	17	4	18	4
Richlands	33	M	87	15	88	15	90	16	90	15	89	15	90	16	90	15	90	15	91	16	92	16
Rocklea	110	M	113	29	115	29	115	30	115	30	115	30	125	32	126	32	126	32	127	33	128	33

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

Connection point	Voltage (kV)	Zone	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
Runcorn	33	M	41	8	41	8	44	8	45	9	45	9	45	9	45	9	45	9	46	9	46	9
South Pine	110	M	686	95	697	97	715	99	713	99	710	98	722	100	723	100	724	100	730	101	739	102
Sumner	110	M	25	8	25	8	25	8	25	8	25	8	25	8	25	8	25	8	25	8	25	8
Tennyson	33	M	128	12	129	12	132	12	131	12	130	12	132	12	132	12	132	12	133	13	134	13
Wecker Road	33	M	95	9	95	9	98	9	99	9	100	9	101	9	101	9	101	9	102	10	103	10
Woolooga (Gympie)	132	M	157	9	157	9	161	9	160	9	159	9	161	9	161	9	161	9	162	9	164	9

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

Connection point (1)	2016/17		2017/18		2018/19		2019/20		2020/21		2021/22		2022/23		2023/24		2024/25		2025/26	
	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)	1,261	444	1,258	442	1,268	448	1,274	452	1,274	452	1,274	452	1,274	452	1,274	452	1,274	452	1,274	452
Transmission connected mining loads (3)	77	31	74	29	78	30	93	36	103	39	106	41	107	41	108	41	108	41	103	39
Transmission connected LNG loads (4)	727	239	742	244	779	256	806	265	777	256	785	258	776	255	776	255	749	246	735	242
Transmission connected rail supply substations (5)(6)	357	-341	357	-341	357	-341	357	-341	357	-341	357	-341	357	-341	357	-341	357	-341	357	-341

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 LNG 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) LNG 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, Moranbah South, Peak Downs and Mt McLaren
- Central West zone – Norwich Park, Gregory, Rocklands, Blackwater, Bluff, Wycarbah, Dingo, 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)	1,269	451	1,262	446	1,269	450	1,274	453	1,272	452	1,272	452	1,272	452	1,272	452	1,272	452	1,272	452
Transmission connected mining loads (3)	71	26	68	24	74	26	95	33	96	33	101	36	101	36	101	36	101	36	96	33
Transmission connected LNG loads (4)	662	218	814	267	775	255	788	259	817	268	789	259	785	258	779	256	775	255	745	245
Transmission connected rail supply substations (5)(6)	357	-341	357	-341	357	-341	357	-341	357	-341	357	-341	357	-341	357	-341	357	-341	357	-341

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 LNG 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) LNG 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, Moranbah South, Peak Downs and Mt McLaren
- Central West zone – Norwich Park, Gregory, Rocklands, Blackwater, Bluff, Wycarbah, Dingo, 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 2016 TAPR 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

Customers other than Energex and Ergon that connect directly to Powerlink's transmission network are assessed based on their forecast, recent history and 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 small-scale solar PV, battery storage, electric vehicles, energy efficiency improvements, smart meters are factored into the forecast 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 energy.

To prepare these forecasts, regression analysis is carried out using native demand and energy plus small-scale solar PV 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.

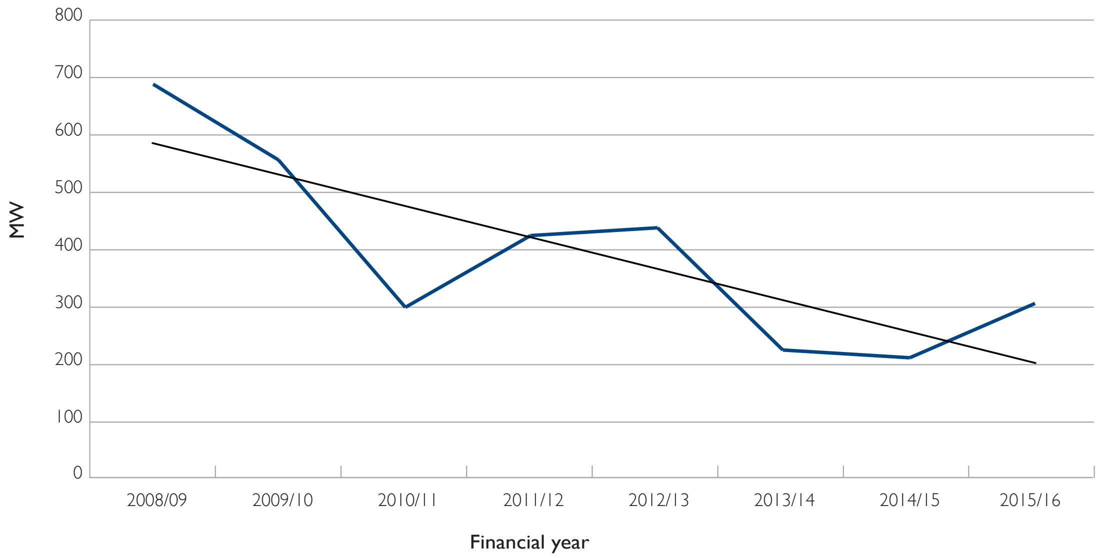
The first step in the regression analysis is to assemble historical native energy and maximum demand values as follows:

a) 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 actuals 12 months later when preparing the next TAPR.

b) Winter maximum demand. The DNSP native demand at the time of winter state peak is collated from winter 2000. These demands are then corrected to average weather conditions. Powerlink has enhanced its method for weather correction as described later in this appendix.

c) Summer maximum demand. The DNSP native demand at the time of summer state peak is collated from summer 2000/01. These demands are then corrected to average weather conditions. DNSP native demand at the time of summer state evening peak (after 6pm) is also collated 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 network due to the increasing impact of small-scale solar PV. This move to an evening peak by 2019/20, 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 corrected maximum demand



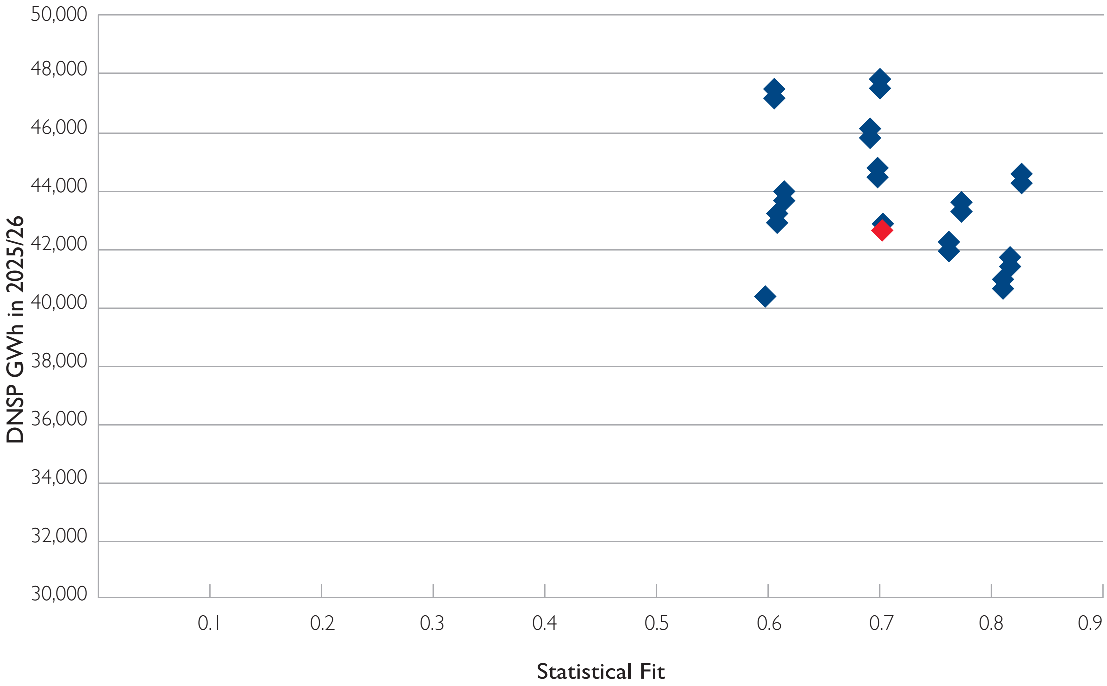
Before the energy data can be used in a regression, it is necessary to make appropriate adjustments to account for small-scale solar PV. This ensures that the full underlying DNSP load is being regressed. As forecast summer maximum demand is now based on an evening regression and winter maximum demand occurs in the evening, only an adjustment for energy is needed. This energy adjustment assumes that small-scale solar PV output averages 15% of capacity. The 15% figure is based on observations through the Australian PV Institute. Following the regression for energy, the forecast is then adjusted down to take into account future small-scale solar PV contributions based on forecast small-scale solar PV capacity.

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. This regression represents the relationship between input and output variables. A logarithmic relationship is used in keeping with statistical good practice.

Input variables are selected from two price variables (supplied by AEMO) 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 and total electricity price with a one year delay. The regression selected reflects a central outcome at the end of the regression period and uses broad based input variables.

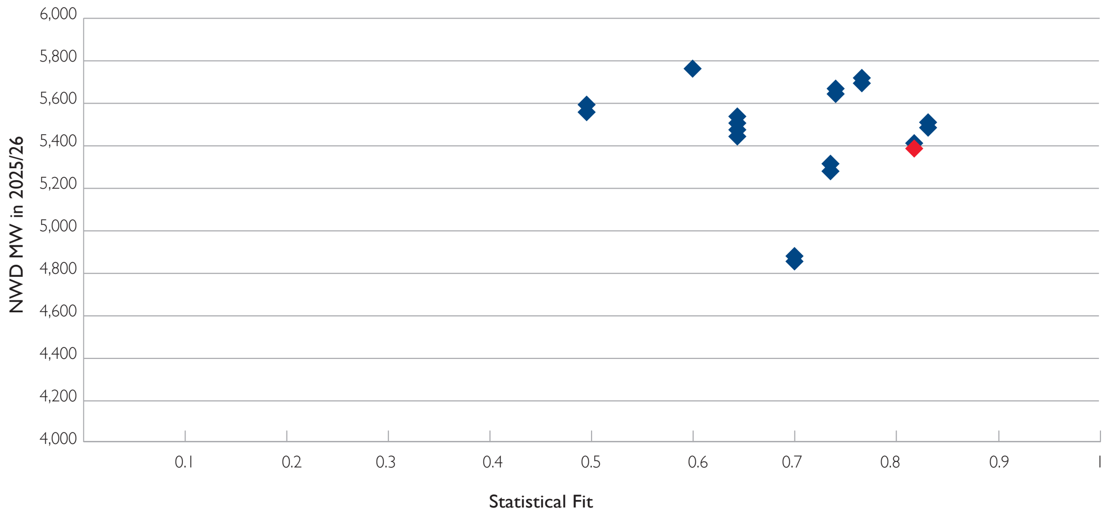
Economic data was supplied for the medium economic outlook with variations derived for low and high economic outlooks. The regression is carried out using medium data leading to the medium economic forecast. High and low energy forecasts are then determined by applying the appropriate forecast economic data to the model.

Summer and winter maximum demand regressions

Maximum demand forecasts are based on two regressions. The corrected 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 maximum demand and the NWD demand based on the previous September. For winter, this is the difference between the corrected 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.

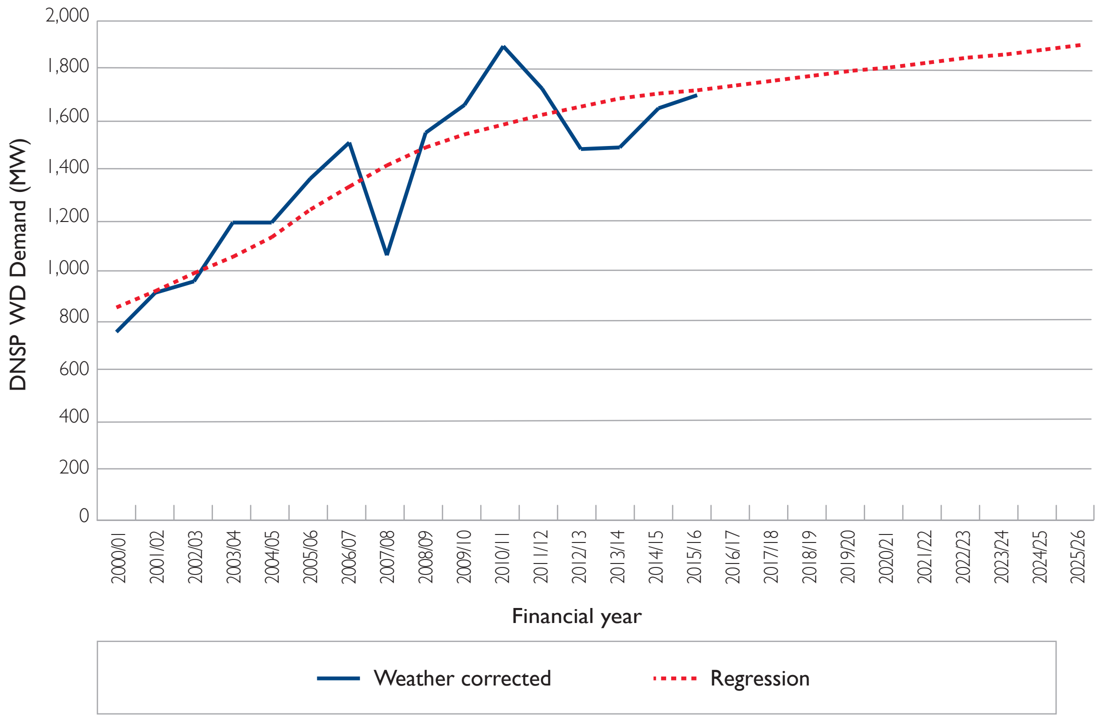
Figure B.3 Non-weather dependent demand regression results



The selected regression shown above in red uses Queensland retail turnover and total electricity price both with a one year delay.

The 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. This variable is a measure of the air conditioning capacity in Queensland and demonstrates a good statistical fit as illustrated in Figure B.4 by the summer regression below. Historical and forecast air conditioning penetration rates are provided annually in the Queensland Household Energy Survey.

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 (probability of exceedance), 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. WD analysis described above is applied to historical demands temperature corrected to 50% PoE conditions. It therefore leads to the 50% PoE forecast. The analysis is repeated using historical demands corrected to 10% PoE and 90% PoE conditions to deliver the other forecasts.

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 for change.

Driven by this commitment, Powerlink again conducted a forum of industry experts to learn more about new technologies and the impacts that they may have on future electrical demand and energy. Based on the information shared for the 2016 Transmission Annual Planning Report, Powerlink adopted technology and other inputs as summarised in Table B.1.

Table B.1 **Difference in summer day and summer evening corrected maximum demand**

	Solar PV	Battery Storage	Energy Efficiency Beyond Trend	Electric Vehicles	Tariff Reform / DSM	Customer Momentum
Energy (GWh)[1]	3,969	0	0	0	0	1,747
Maximum demand (MW)[2]	0	240	0	0	120	307
Installed capacity MW in 2025/26	4,300					
First year of impact	now	2017/18			2018/19	2016/17

Notes:

(1) This is the energy reduction in financial year 2025/26 compared to 2015/16.

(2) This is the maximum demand reduction in summer 2025/26 compared to summer 2015/16.

Powerlink recognises there is considerable uncertainty regarding the impact of new technology and other inputs on the demand and energy forecasts. Further, Powerlink recognises a range of other outcomes could have been adopted. Due to these uncertainties Powerlink has provided this additional information to provide transparency and allow other levels to be factored into the demand forecasts if desired.

Small-scale solar PV

The installed capacity of small-scale solar PV in Queensland as at the end of 2015 was 1,500MW. 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.

Of the 1,500MW installed capacity, around 100MW is non-residential. Despite moderation in residential installations, growth in commercial and industrial installations are expected to make up the shortfall, maintaining 20MW per month of installations over the 10-year forecast period. Furthermore, as battery storage systems fall in price it is expected that an additional 200MW worth of small-scale solar PV will connect by 2025/26. In total, this will increase capacity of small-scale solar PV in Queensland to 4,300MW by 2025/26. This is around 600MW above the forecast in the 2015 TAPR.

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[1] Based on information from the Clean Energy Website

Analysis has revealed that Queensland will move to a summer evening peak by 2019/20 and so further small-scale 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 15%[2] capacity.

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

Future impacts of small-scale 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 small-scale solar PV installation levels could increase beyond this forecast.

Battery storage

Battery storage technology has the potential to significantly change the electricity supply industry. 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 small-scale 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 small-scale solar PV generation
- practical issues such as space, aesthetics and safety
- whether economies of scale favour a particular level of aggregation.

The 2015 Queensland Household Energy Survey (QHES) indicates around 9% of Queensland households are considering to purchase a battery storage system. However this same feedback indicates that most people underestimate the current price of installing a storage solution. Assuming half of those households who have expressed an interest proceed to installation as prices drop there will be 100,000 household systems installed by 2025/26. If 80% of these households have someone home at the time of state peak (7pm) and assuming an average of 3kW load per household, a reduction in state peak demand of 240MW is estimated.

Energy Efficiency

Future energy efficiency improvements are now expected to continue broadly in line with historical trends. Over the last six months a report commissioned by Energex relating to household efficiency in South East Queensland (SEQ) and the QHES both support future energy efficiency improvements in line with historical trends. The QHES notes that Queensland consumers have now become less frugal and are more inclined to use air conditioning during warm weather. The forecasting reference group[3] recently noted that above historical trend improvements such as pink batts and low cost LEDs are not expected to be repeated. As such additional energy efficiency gains beyond these historic levels are forecast to be hard to achieve. As a result in this updated forecast energy efficiency improvements have been brought into line with historical trends.

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

[3] This is a national electricity forecasting group convened by AEMO

Electric vehicles

Compared to world leading countries in electric vehicle uptake such as Norway and the Netherlands, the uptake of electric vehicles in Australia is quite low. Without significant government policy changes to actively encourage their purchase this is not expected to change in the short-term. Ultimately, the efforts by manufacturers such as Tesla to lower battery costs and improve performance will drive up sales. Powerlink has continued not to include a specific allowance in its demand and energy forecast for electric vehicles but will continue to monitor progress in this area. In the event that there is a significant update in electric vehicles it is expected that most owners will be incentivised to charge their cars at off peak times resulting in minimal increase in peak demand. Similarly it is estimated a 1% penetration of electric vehicles on the road would result in approximately 0.3% increase in total energy usage.

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 the batteries during peak demand / high price times. The extent to which this occurs will depend on how quickly new tariffs are offered 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 per cent of trials internationally have resulted in peak reductions of 10 per cent or more."[4]

A big challenge to tariff reform is gaining consumer acceptance. Many consumers dislike complicated tariffs and any move to remove existing tariff cross subsidies will meet resistance from those currently benefitting from them.

Some of this peak reduction will already be captured through the battery storage allowance above. An additional 120MW has been assumed within this forecast and represents a further 1.5% of the total maximum demand from the Energex and Ergon networks. As tariff reform is likely to result in load shifting, the impact on energy is expected to be low.

Customer momentum factor

Over the last 10 years, the price of electricity in Queensland has nearly doubled. This has led many customers to adopt frugal behaviours in an effort to minimise the financial impact. The price used in the regression model now forecasts an increase of 4% over the next 10 years. The logic hardwired in the regression model suggests that customers will lessen their frugal behaviour in response to moderating electricity prices. Powerlink's view is that people may not be so quick to change behaviour. Observed behaviour during a history of rising electricity prices may not be the ideal predictor of behaviour during a period of relatively flat prices.

To allow for this effect, a new 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 that energy and demand will not bounce back with the moderation of electricity prices.

In future years when additional information on customers' actual behaviour during moderating electricity prices is captured in the data series, this factor will be removed.

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

Weather correction methodology

Peak 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. 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% Probability of Exceedance (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).

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.
- Exclude mild days and holidays: To ensure that the fitted model accurately describes the relationship between temperature and peak demand on days when demand is high, days with mild weather, and the two-week period around Christmas (when many businesses are closed) are filtered out of the dataset.
- Calculate a regression model for each year: A regression model is calculated for each year, 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.
- Determine the 10% and 50% PoE thresholds using 20 years of weather data: The model calculated for each season is then applied to the daily weather data recorded since 1995. This effectively calculates what the peak demand would have been on each day if the relationship between peak 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 twenty 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 2015/16 summer was hotter than average. Therefore, the 50% PoE demand is 170MW lower than the observed peak demand. The 2015 winter was cooler than average, resulting in an downwards adjustment of 110MW to the observed winter peak 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 2016 to summer 2018/19. 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 2016 Queensland maximum demand 300MW northerly QNI flow
Figure C.4	Winter 2016 Queensland maximum demand 0MW QNI flow
Figure C.5	Winter 2016 Queensland maximum demand 700MW southerly QNI flow
Figure C.6	Winter 2017 Queensland maximum demand 300MW northerly QNI flow
Figure C.7	Winter 2017 Queensland maximum demand 0MW QNI flow
Figure C.8	Winter 2017 Queensland maximum demand 700MW southerly QNI flow
Figure C.9	Winter 2018 Queensland maximum demand 300MW northerly QNI flow
Figure C.10	Winter 2018 Queensland maximum demand 0MW QNI flow
Figure C.11	Winter 2018 Queensland maximum demand 700MW southerly QNI flow
Figure C.12	Summer 2016/17 Queensland maximum demand 200MW northerly QNI flow
Figure C.13	Summer 2016/17 Queensland maximum demand 0MW QNI flow
Figure C.14	Summer 2016/17 Queensland maximum demand 400MW southerly QNI flow
Figure C.15	Summer 2017/18 Queensland maximum demand 200MW northerly QNI flow
Figure C.16	Summer 2017/18 Queensland maximum demand 0MW QNI flow
Figure C.17	Summer 2017/18 Queensland maximum demand 400MW southerly QNI flow
Figure C.18	Summer 2018/19 Queensland maximum demand 200MW northerly QNI flow
Figure C.19	Summer 2018/19 Queensland maximum demand 0MW QNI flow
Figure C.20	Summer 2018/19 Queensland maximum demand 400MW southerly QNI flow

The power flows reported in this appendix assume the open points at 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 – possible 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 2016	Winter 2017	Winter 2018	Summer 2016/17	Summer 2017/18	Summer 2018/19	
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 132 kV (1 circuit)	177/177/177	178/178/178	182/182/182	220/220/220	225/225/225	224/224/224	V
CQ-NQ Bouldercombe into Nebo 275kV (1 circuit) Broadsound into Nebo 275kV (3 circuits) Dysart to Peak Downs/Moranbah 132kV (1 circuit) Dysart to Eagle Downs 132kV (1 circuit)	660/660/660	655/655/655	668/668/668	799/799/799	805/805/805	805/805/805	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)	714/724/732	661/710/717	674/590/718	608/609/613	589/590/594	593/595/599	Th
CQ-SQ Wurdong into Gin Gin 275kV (1 circuit) Calliope River into Gin Gin 275kV (2 circuits) Calvale into Halys 275kV (2 circuits)	1,706/1,675/1,675	1,499/1,655/1,655	1,487/1,789/1,631	1,733/1,733/1,733	1,726/1,726/1726	1,718/1,718/1,718	Tr V
Surat Western Downs to Columboola 275kV (1 circuit) Western Downs to Orana 275kV (1 circuit) Tarong into Chinchilla 132kV (2 circuits)	490/490/490/	627/627/627	589/589/589	527/527/527	539/539/539	576/576/576	V
SWQ Western Downs to Halys 275kV (2 circuits) Braemar (East) to Halys 275kV (2 circuits) Millmerran to Middle Ridge 330kV (2 circuits)	1,141/1,168/1,234	1,018/868/934	1,040/752/968	1,761/1,759/1,788	1,395/1,395/1,427	1,393/1,394/1,426	(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)	3,241/3,259/3,319	3,010/2,939/2,999	3,033/2,881/3,029	3,843/3,843/3,872	3,495/3,494/3,524	3,492/3,491/3,520	V

Table C.1: Summary of figures C.3 to C.20 – possible 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 2016	Winter 2017	Winter 2018	Summer 2016/17	Summer 2017/18	Summer 2018/19	
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)	709/709/771	712/712/775	715/715/777	777//777/808	780/780/811	776/776/807	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 2016	Winter 2017	Winter 2018	Summer 2016/17	Summer 2017/18	Summer 2018/19	Significant dependence on	Minor dependence on
Chalumbin 275/132kV (2x200MVA)	FN	38	48	48	34	48	48	Kareeya generation	
Woree 275/132kV (2x375MVA)	FN	122	124	122	159	159	159	Barron Gorge generation	Kareeya, Townsville and Mt Stuart generation
Ross 275/132kV (3x250)	R	125	123	114	196	187	178	Mt Stuart, Townsville and Invicta generation	
Nebo 275/132kV (1x200MVA, 1x250MVA and 1x375MVA)	N	271	278	286	293	297	298	Mackay generation	
Strathmore 275/132kV (1x375MVA)	N	110	111	116	126	128	129	Invicta generation	Townsville and Mt Stuart generation
Bouldercombe 275/132kV (2x200MVA and 1x375MVA)	CW	148	148	149	187	188	188		
Calvale 275/132kV (1x250MVA)	CW	129	135	140	129	136	124	Callide, Yarwun and Gladstone generation and 132kV network configuration	
Lilyvale 275/132kV (2x375MVA)	CW	203	217	217	221	219	228	Barcaldine generation	CQ-NQ flow
Larcom Creek 275/132 kV (2x375MVA)	G	67	67	67	56	55	56	Yarwun generation	
Gin Gin 275/132kV (2x250MVA)	WB	127	137	141	151	151	150		CQ-SQ flow
Teebar Creek 275/132kV (2x375MVA)	WB	74	78	74	76	76	76		CQ-SQ flow
Woolooga 275/132kV (2x250MVA)	WB	212	214	223	217	215	213		CQ-SQ flow
Columboola 275/132kV (2x375MVA)	S	162	186	111	188	111	113	Roma and Condamine generation	SW generation and 132kV network configuration
Middle Ridge 275/110kV (3x250MVA)	SW	264	266	265	260	260	260	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 2016	Winter 2017	Winter 2018	Summer 2016/17	Summer 2017/18	Summer 2018/19	Significant dependence on	Minor dependence on
Tarong 275/132kV (2x90MVA)	SW	26	43	37	14	19	22	Roma and Condamine generation	SW generation and 132kV network configuration
Tarong 275/66kV (2x90MVA)	SW	37	37	37	29	29	29		
Abermain 275/110kV (1x375MVA)	M	140	146	147	171	174	175	110kV transfers to/from Blackstone and Goodna	Tarong flow
Belmont 275/110kV (2x250 and 2x375 MVA)	M	507	512	516	600	611	605	110kV transfers to/from Loganlea	110kV transfers to/from Rocklea and Swanbank E generation
Blackstone 275/110kV (1x250 and 1x240MVA)	M	153	172	173	195	210	211		
Goodna 275/110kV (1x375MVA)	M	130	128	129	163	161	161	110kV transfers to/from Blackstone and Abermain	
Loganlea 275/110kV (2x375MVA)	M	348	353	355	401	413	405	110kV transfers to/from Belmont	110kV transfers to/from Molendinar and Mudgeeraba and Swanbank E generation
Murarrie 275/110kV (2x375MVA)	M	339	341	344	365	369	370		
Palmwoods 275/132kV (2x375MVA)	M	312	321	323	304	310	305		CQ-SQ flow
Rocklea 275/110kV (2x375MVA)	M	312	307	308	389	384	383	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	593	605	607	664	670	666		
South Pine West 275/110kV (1x375, 1x250MVA)	M	239	231	232	299	291	290		CQ-SQ flow and Swanbank E generation
Molendinar 275/110kV (2x375MVA)	GC	423	428	428	456	458	455	110kV transfers to/from Loganlea and Mudgeeraba	Terranora Interconnector
Mudgeeraba 275/110kV (3x250MVA)	GC	375	377	378	391	393	426	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

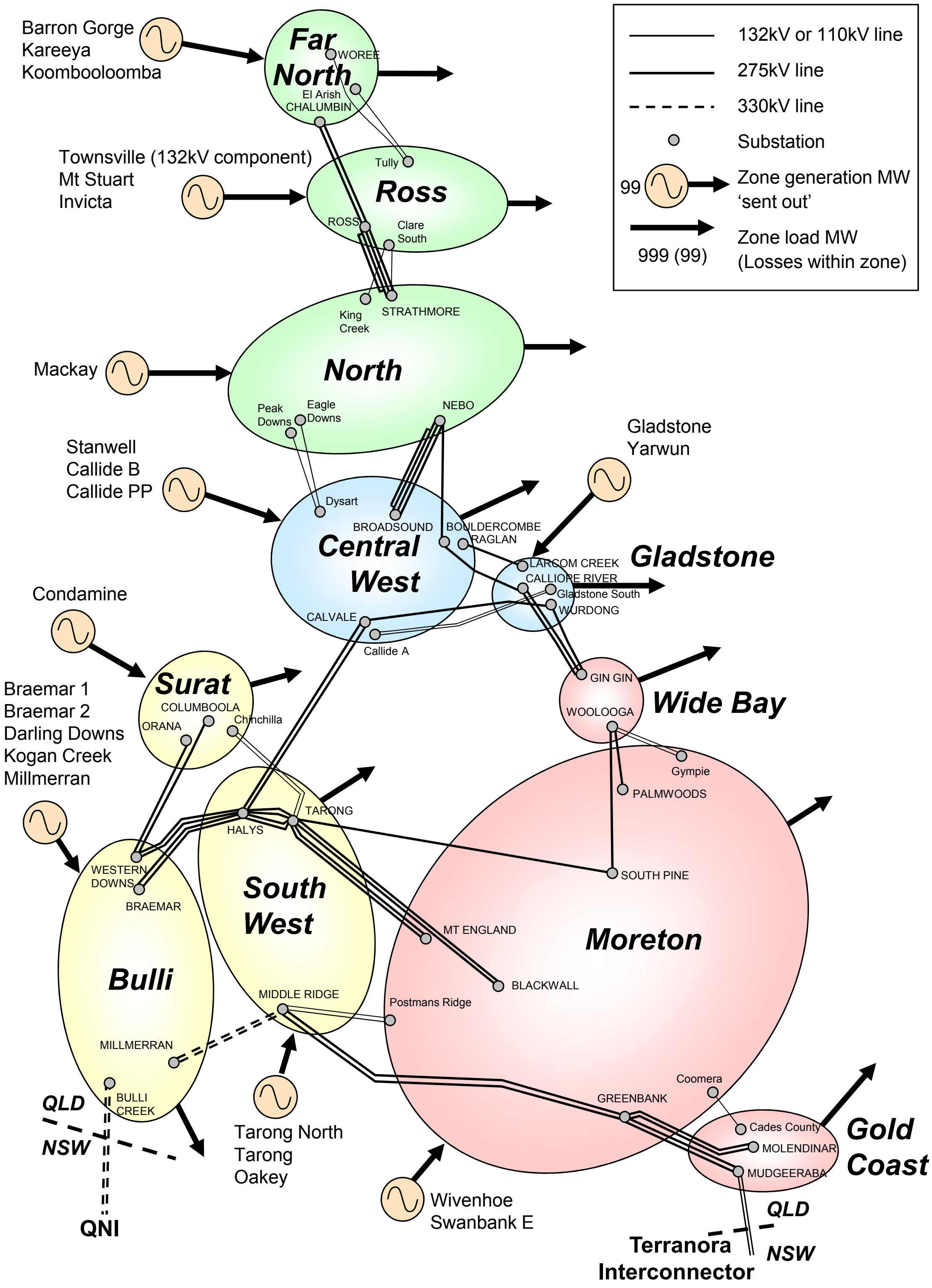


Figure C.2 Grid section legend for figures C.3 to C.20

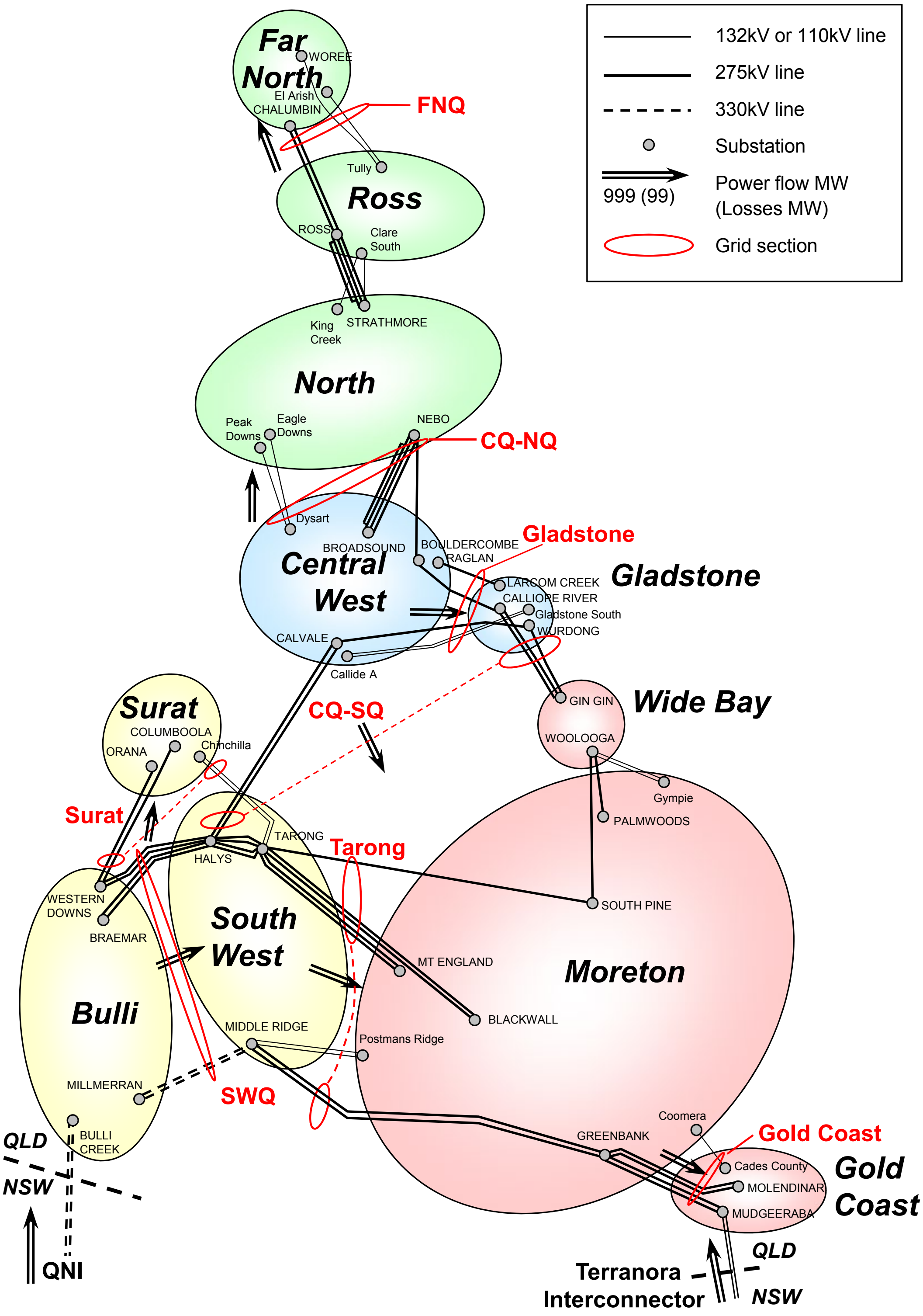
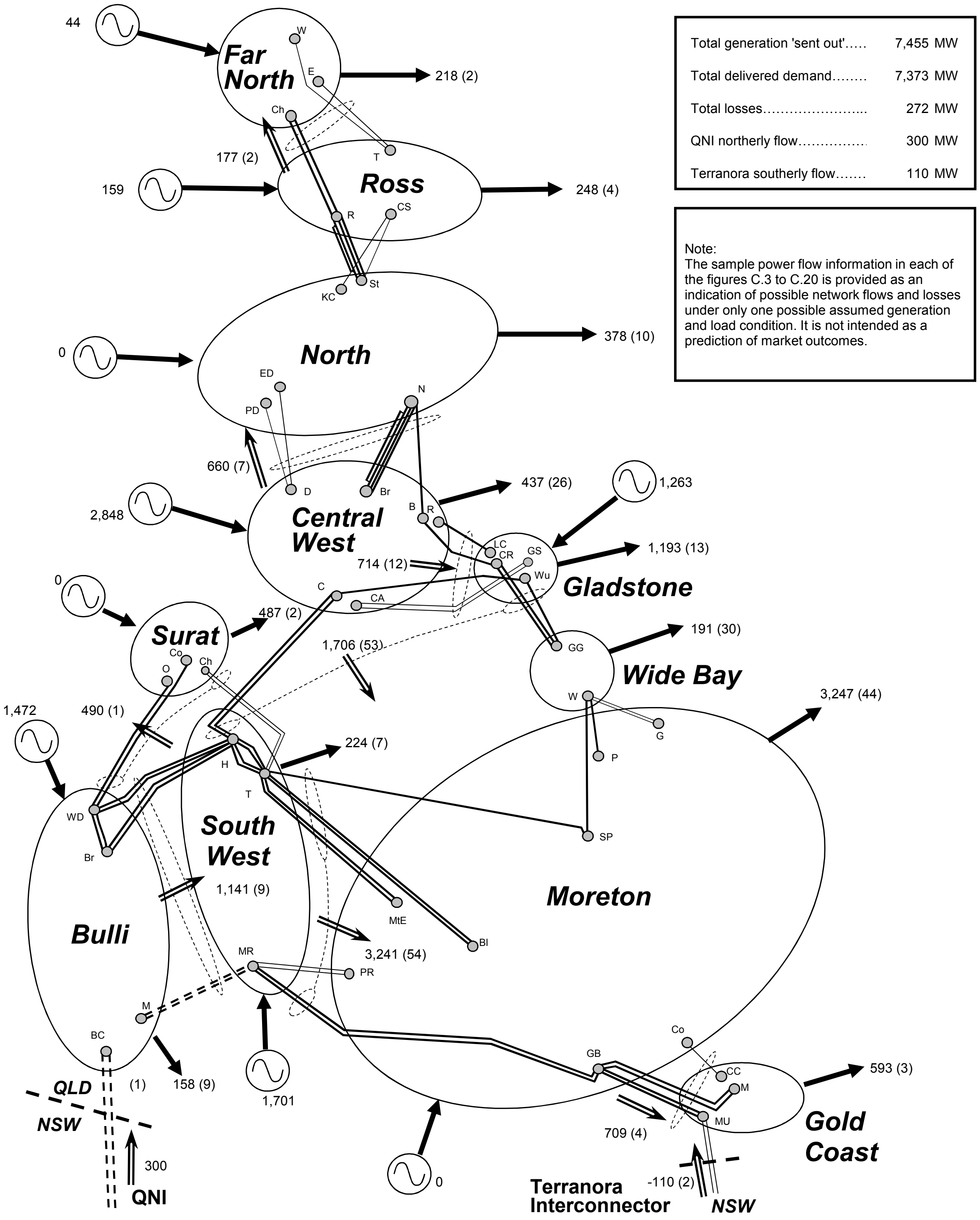


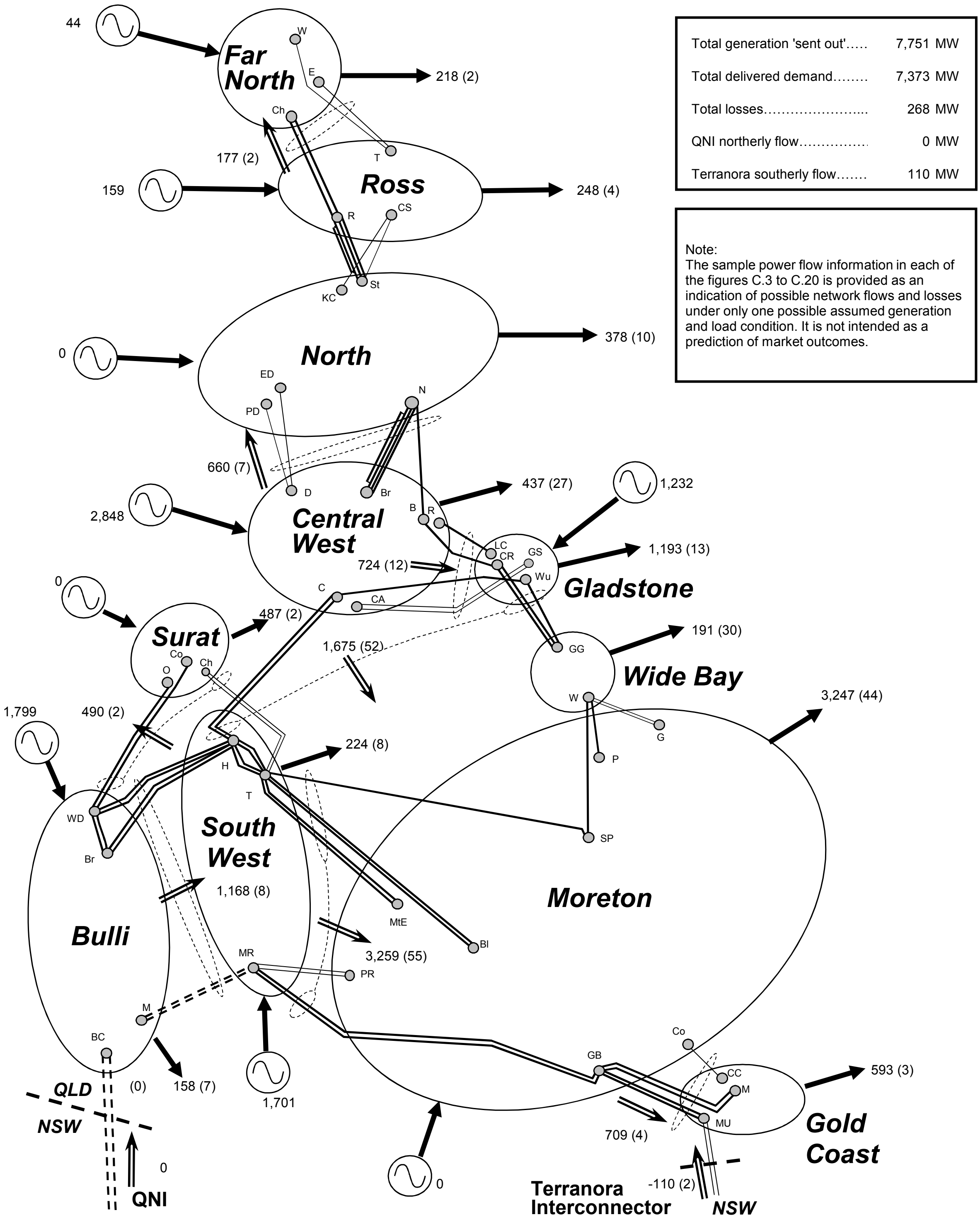
Figure C.3 Winter 2016 Queensland maximum demand 300MW northerly QNI flow



Total generation 'sent out'.....	7,455 MW
Total delivered demand........	7,373 MW
Total losses........................	272 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.

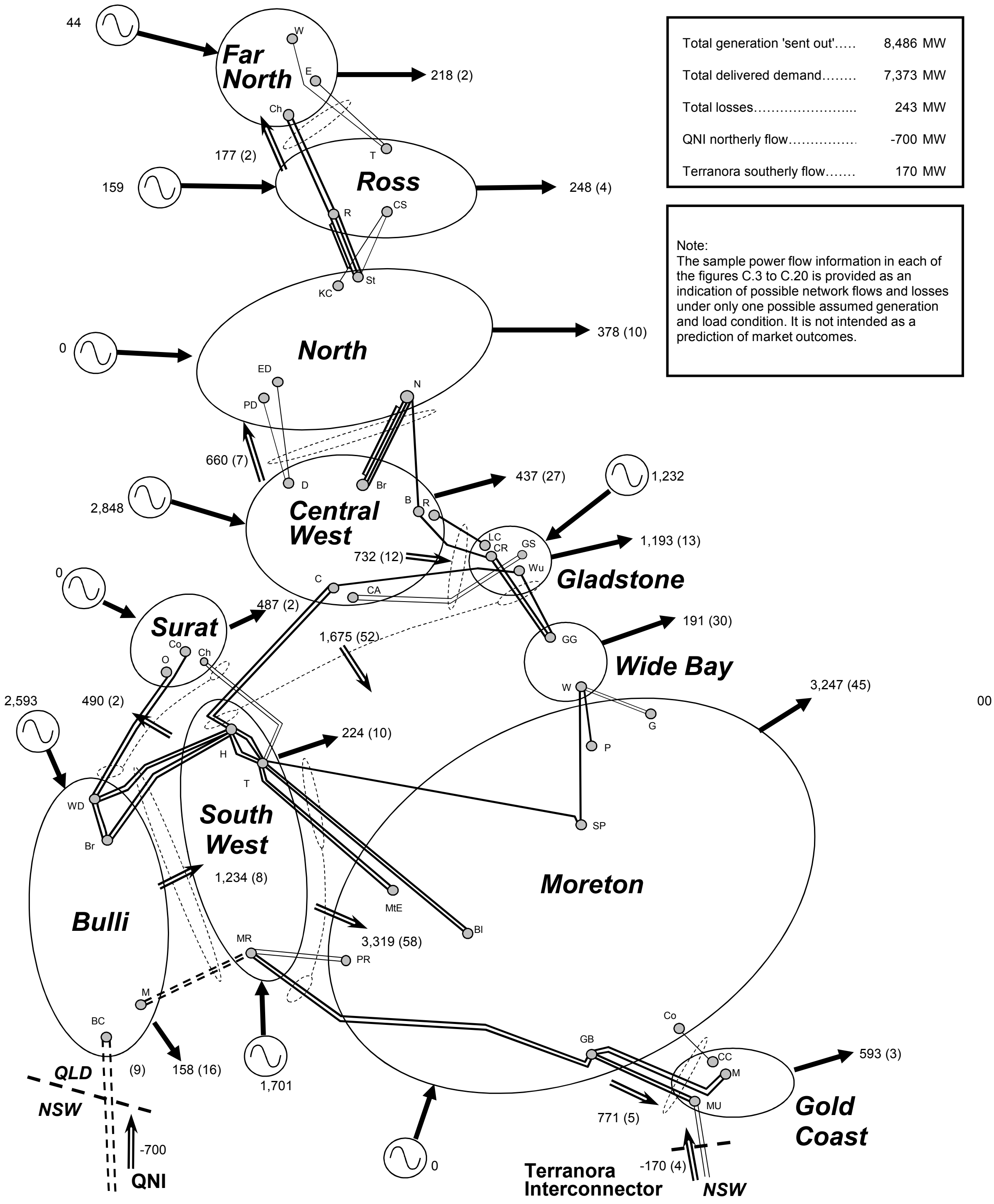
Figure C.4 Winter 2016 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'…..	7,751 MW
Total delivered demand……..	7,373 MW
Total losses…………………...	268 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.

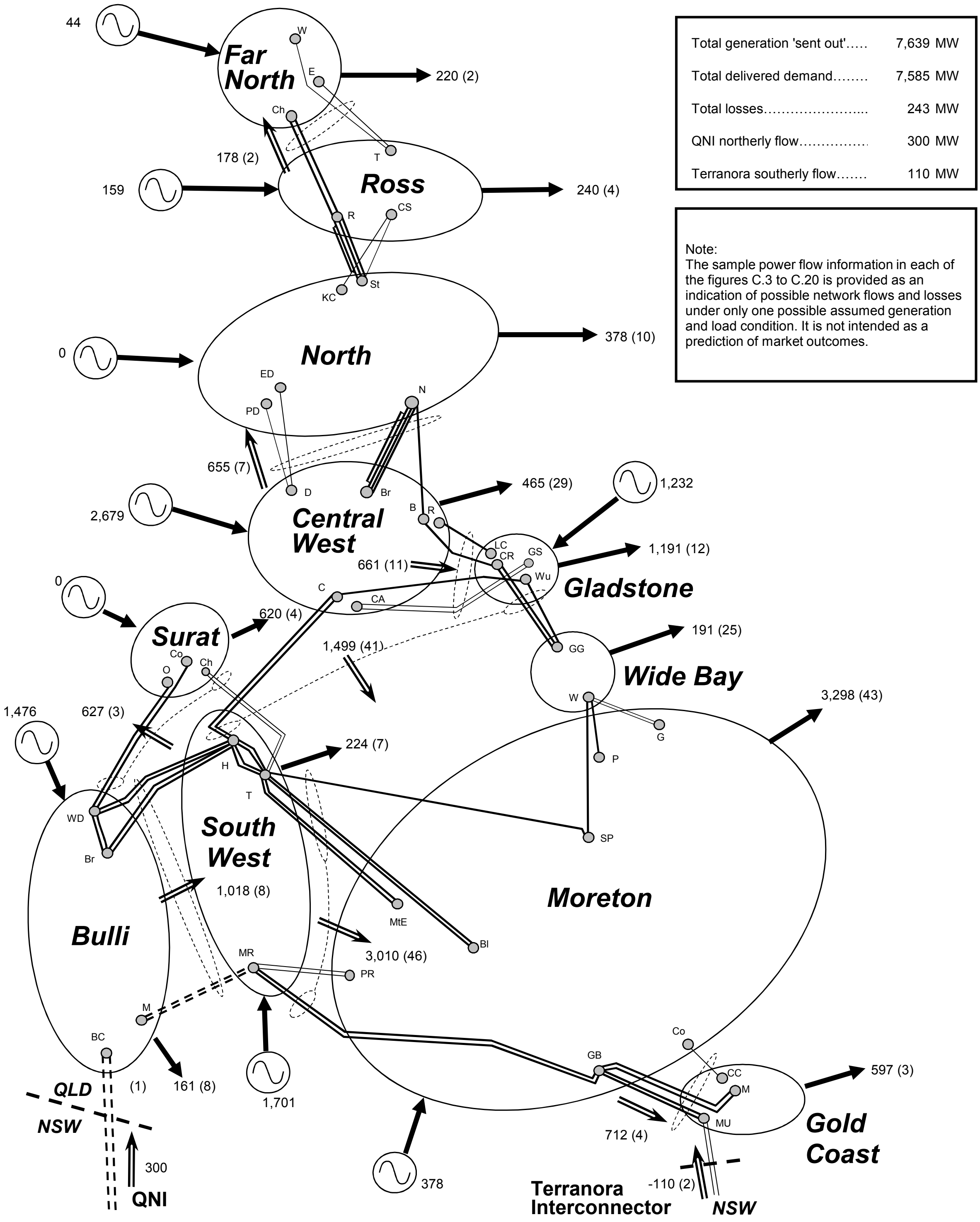
Figure C.5 Winter 2016 Queensland maximum demand 700MW southerly QNI flow



Total generation 'sent out'…..	8,486 MW
Total delivered demand……..	7,373 MW
Total losses…………………..	243 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.

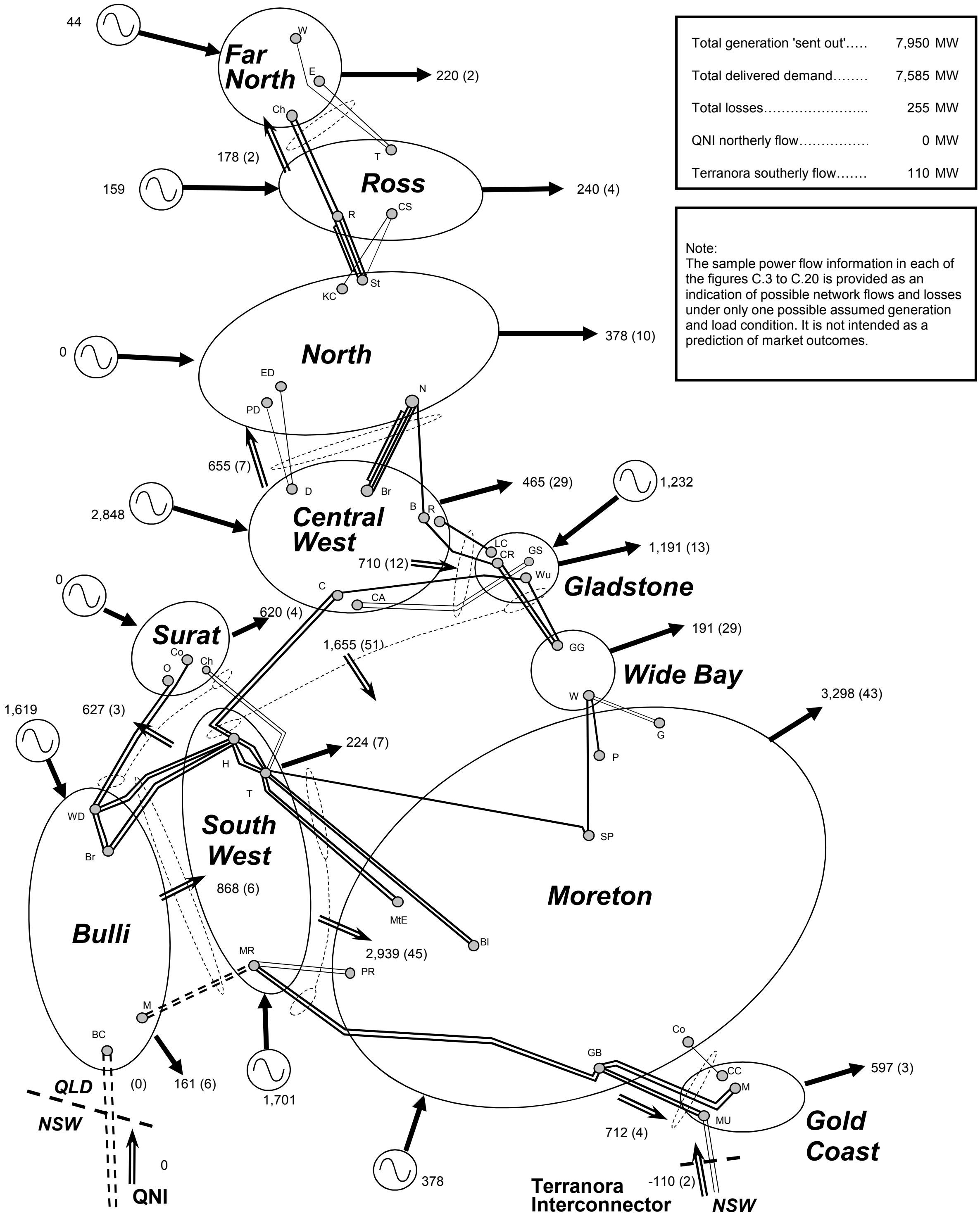
Figure C.6 Winter 2017 Queensland maximum demand 300MW northerly QNI flow



Total generation 'sent out'…..	7,639 MW
Total delivered demand……..	7,585 MW
Total losses…………………...	243 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.

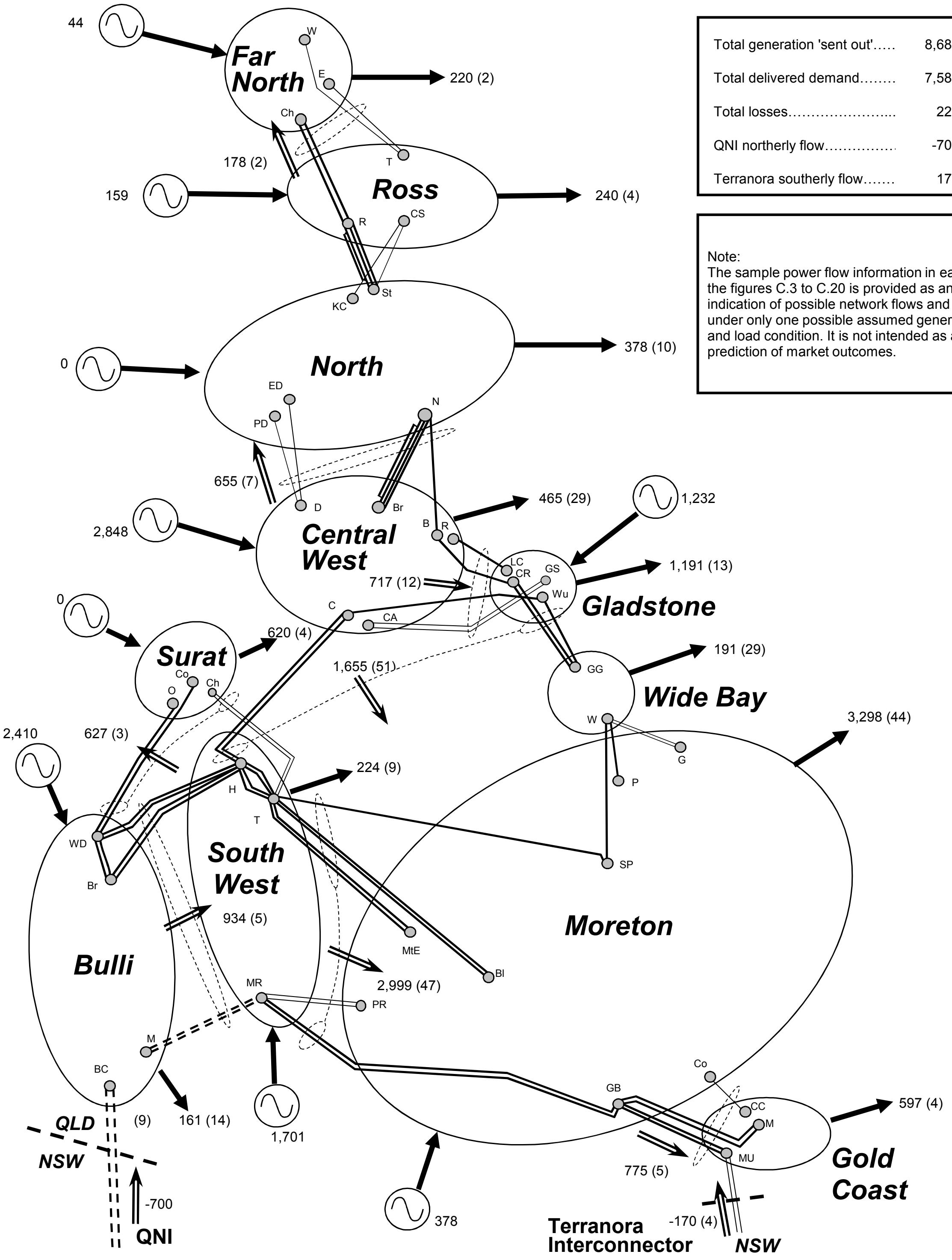
Figure C.7 Winter 2017 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'…..	7,950 MW
Total delivered demand……..	7,585 MW
Total losses…………………...	255 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.

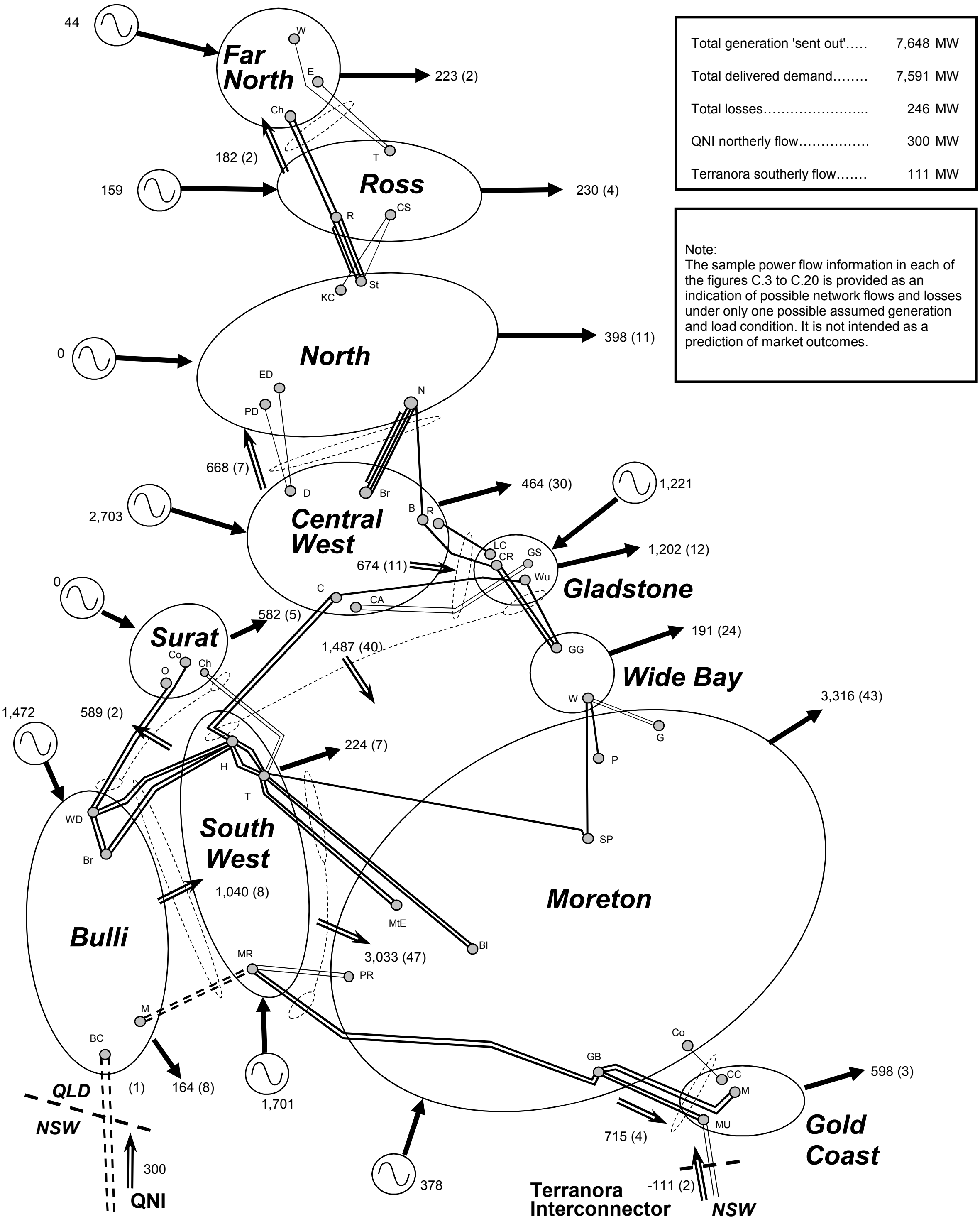
Figure C.8 Winter 2017 Queensland maximum demand 700MW southerly QNI flow



Total generation 'sent out'…..	8,682 MW
Total delivered demand……..	7,585 MW
Total losses…………………...	226 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.

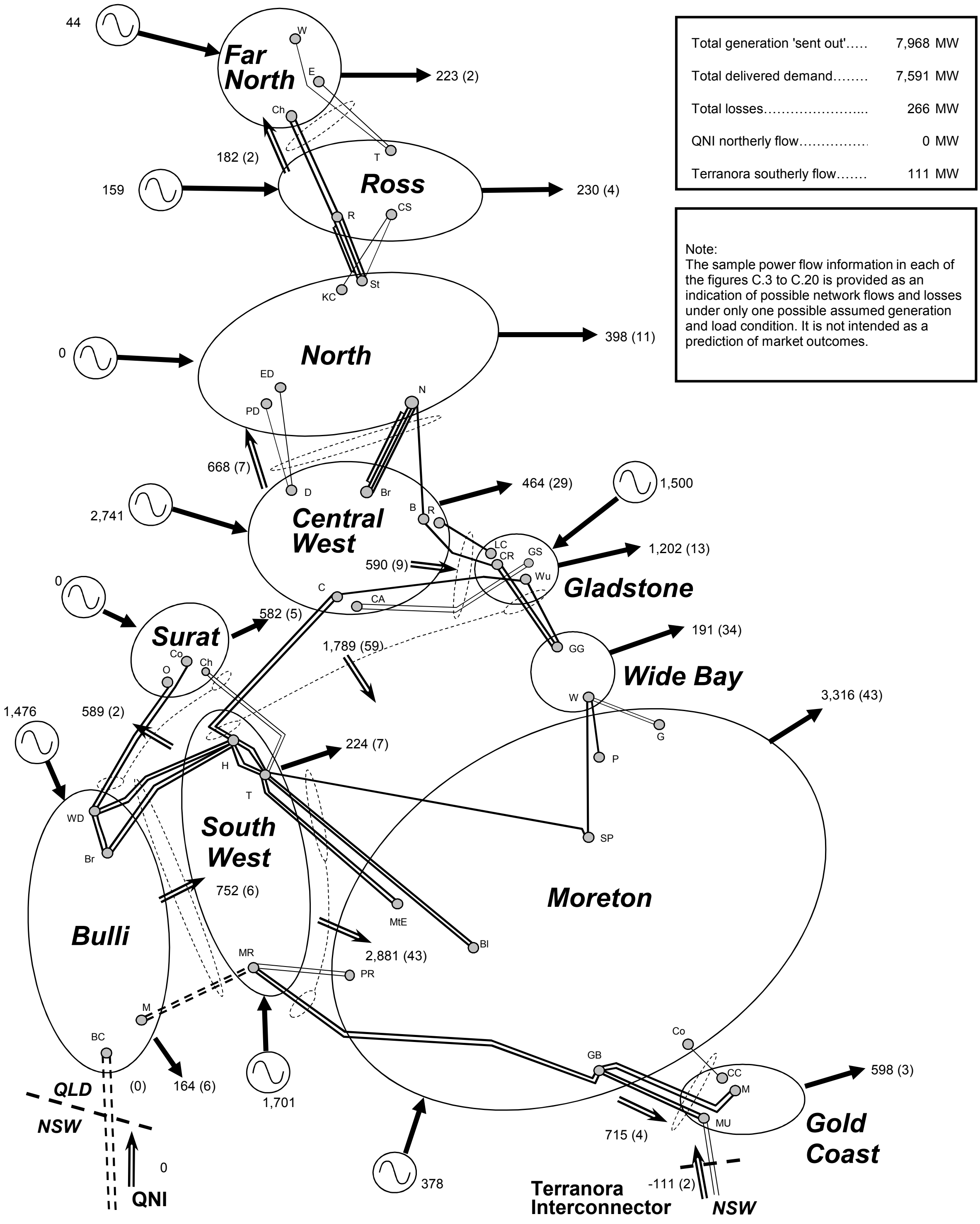
Figure C.9 Winter 2018 Queensland maximum demand 300MW northerly QNI flow



Total generation 'sent out'.....	7,648 MW
Total delivered demand........	7,591 MW
Total losses........................	246 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.

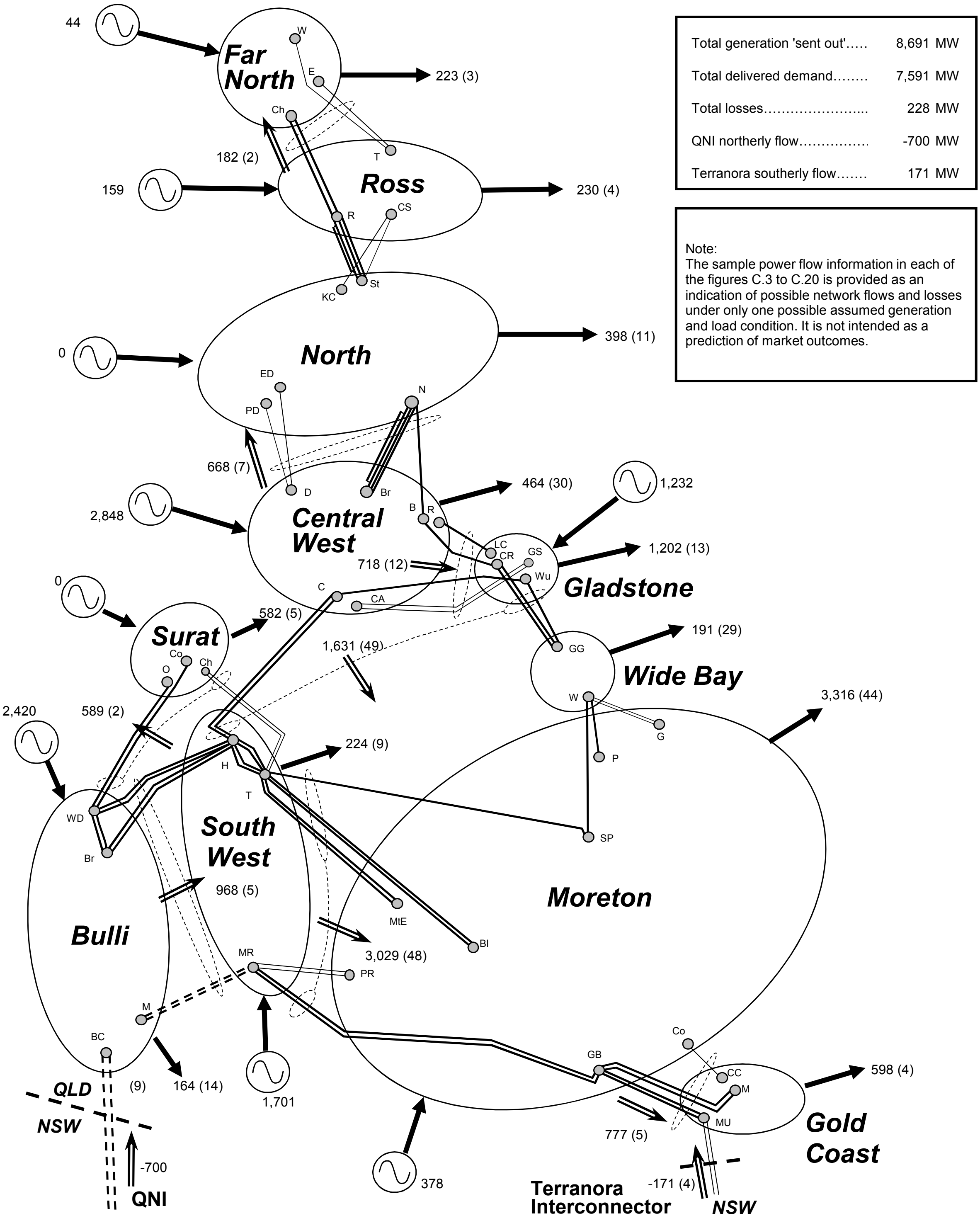
Figure C.10 Winter 2018 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'…..	7,968 MW
Total delivered demand……..	7,591 MW
Total losses…………………...	266 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.

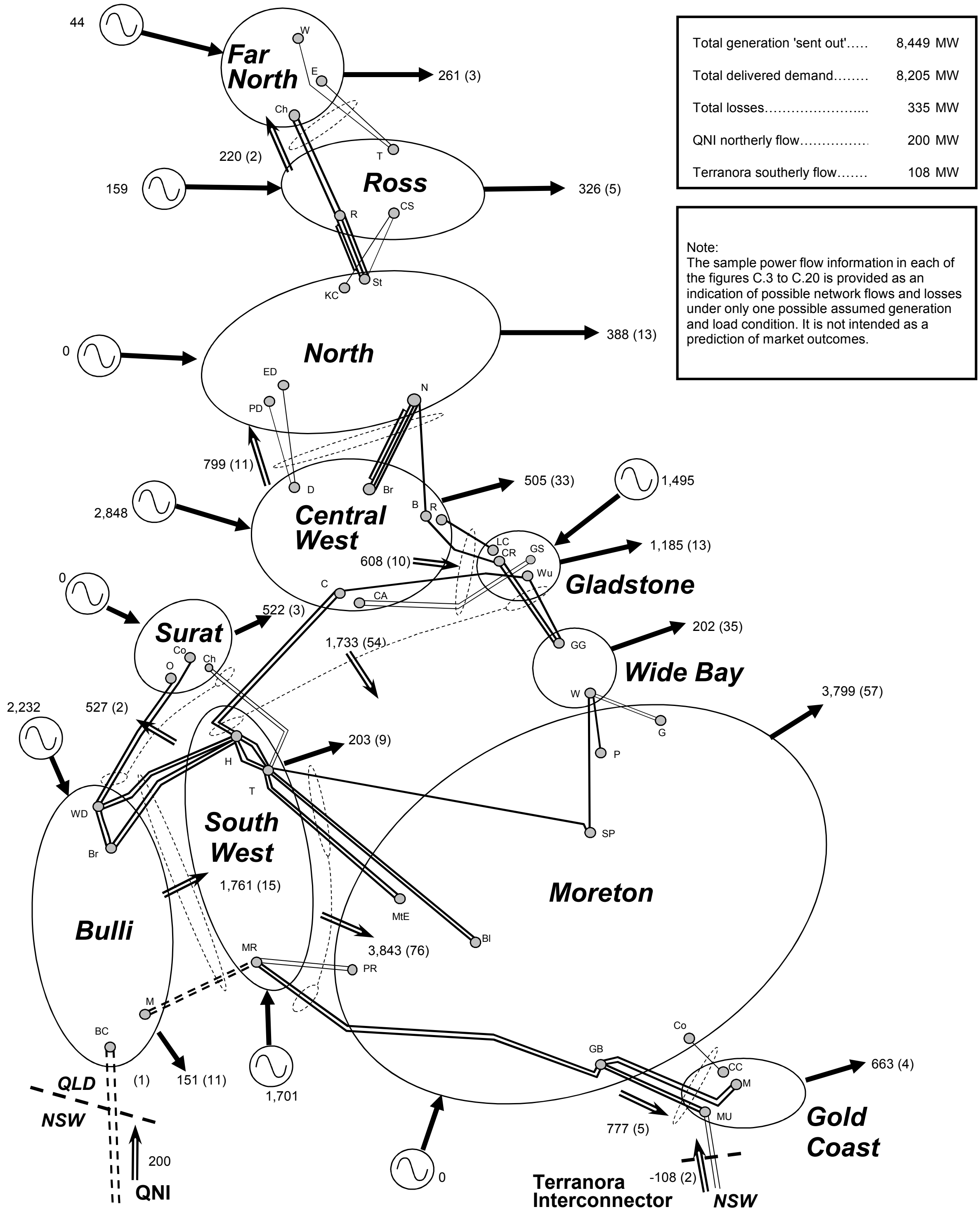
Figure C.11 Winter 2018 Queensland maximum demand 700MW southerly QNI flow



Total generation 'sent out'…..	8,691 MW
Total delivered demand……..	7,591 MW
Total losses…………………...	228 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.

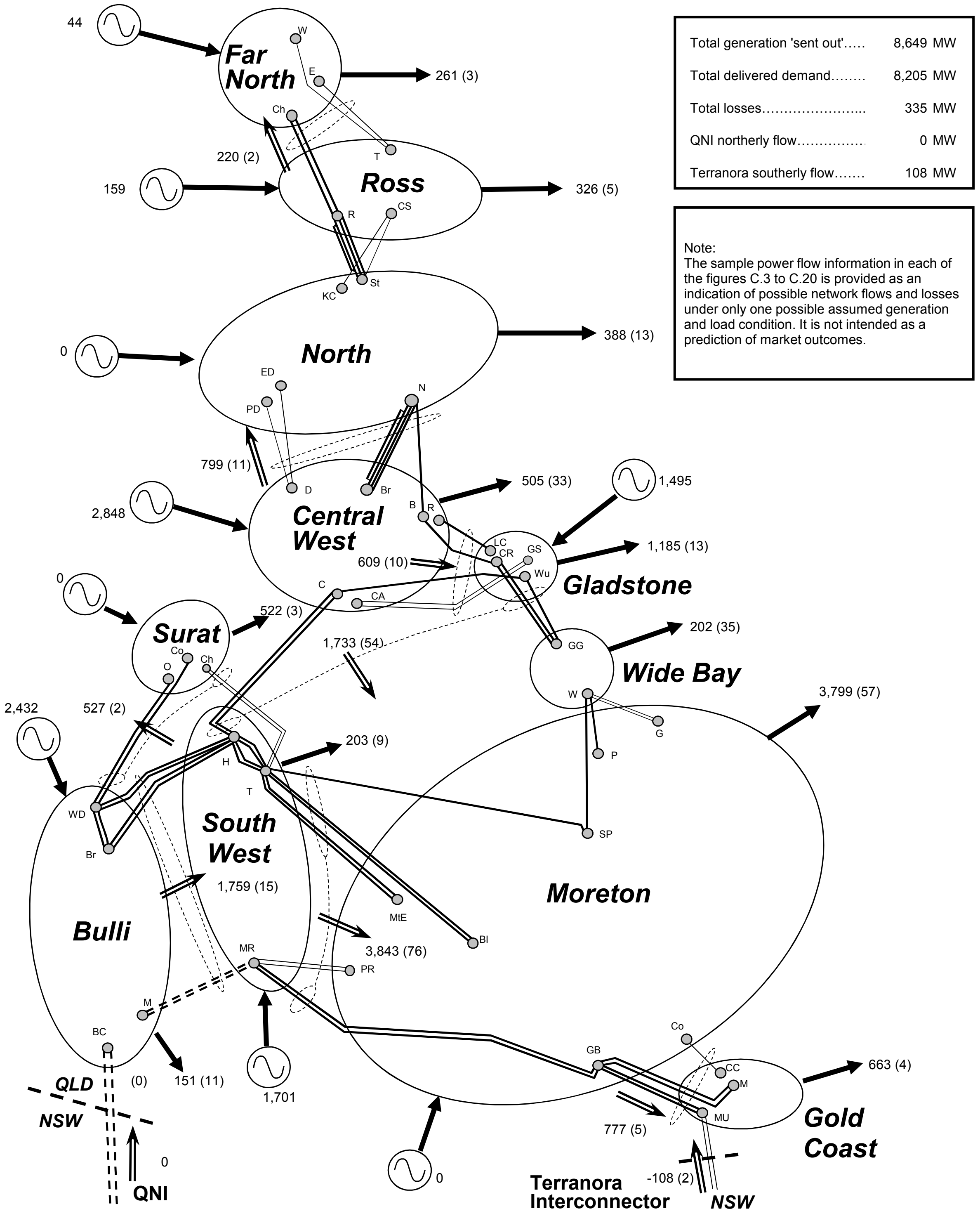
Figure C.12 Summer 2016/17 Queensland maximum demand 200MW northerly QNI flow



Total generation 'sent out'…..	8,449 MW
Total delivered demand……..	8,205 MW
Total losses…………………....	335 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.

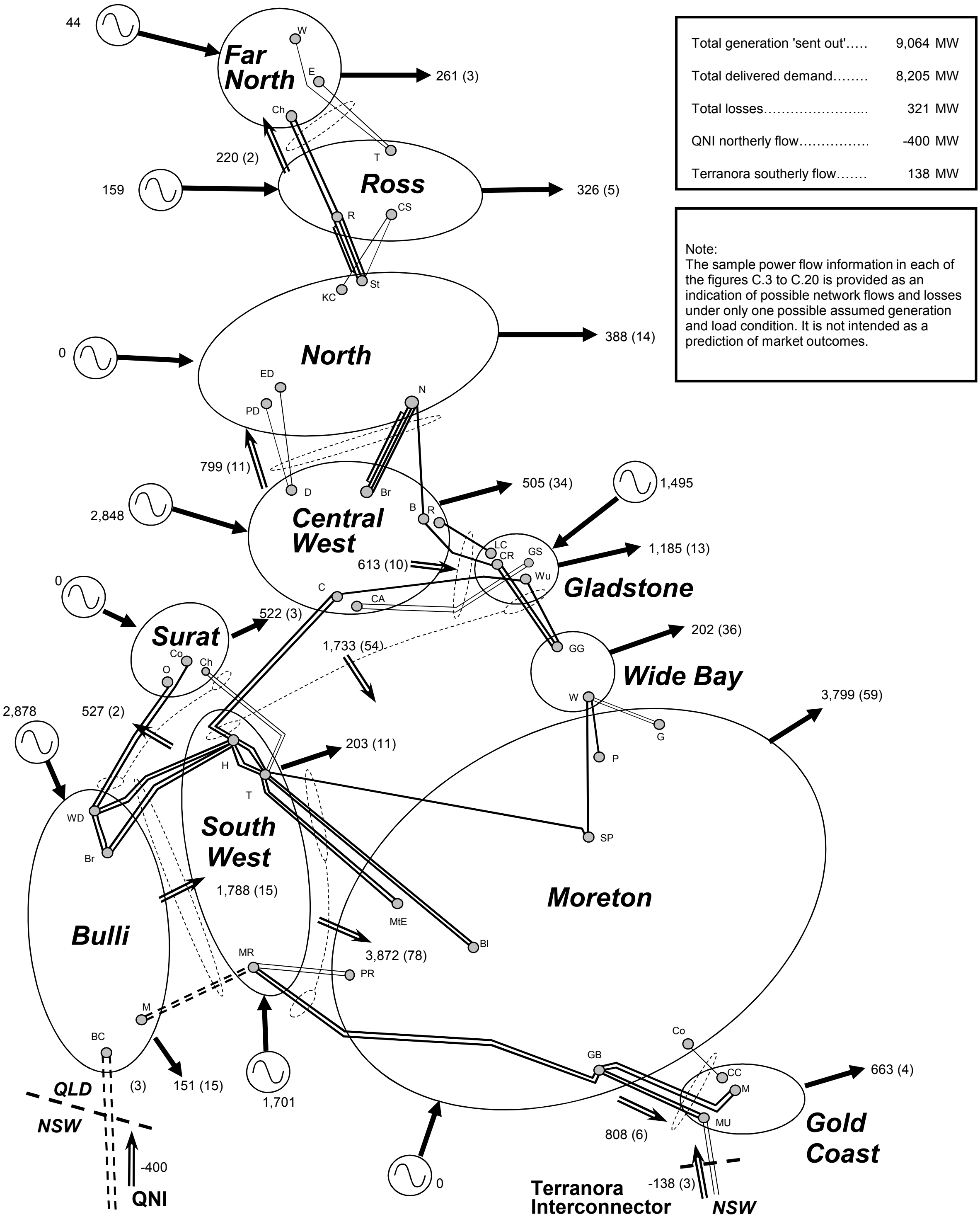
Figure C.13 Summer 2016/17 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'…..	8,649 MW
Total delivered demand……..	8,205 MW
Total losses…………………..	335 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.

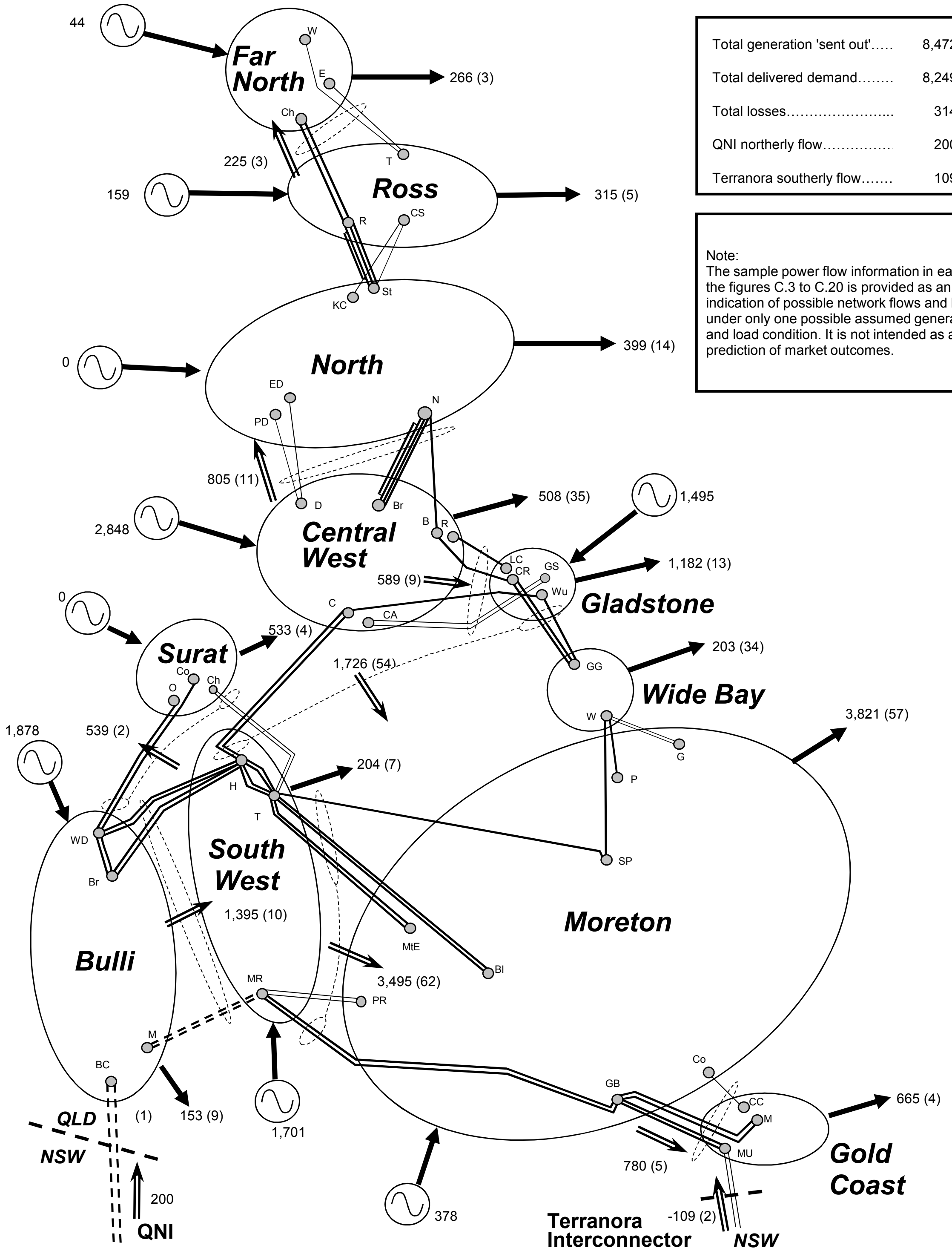
Figure C.14 Summer 2016/17 Queensland maximum demand 400MW southerly QNI flow



Total generation 'sent out'…..	9,064 MW
Total delivered demand……..	8,205 MW
Total losses…………………....	321 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.

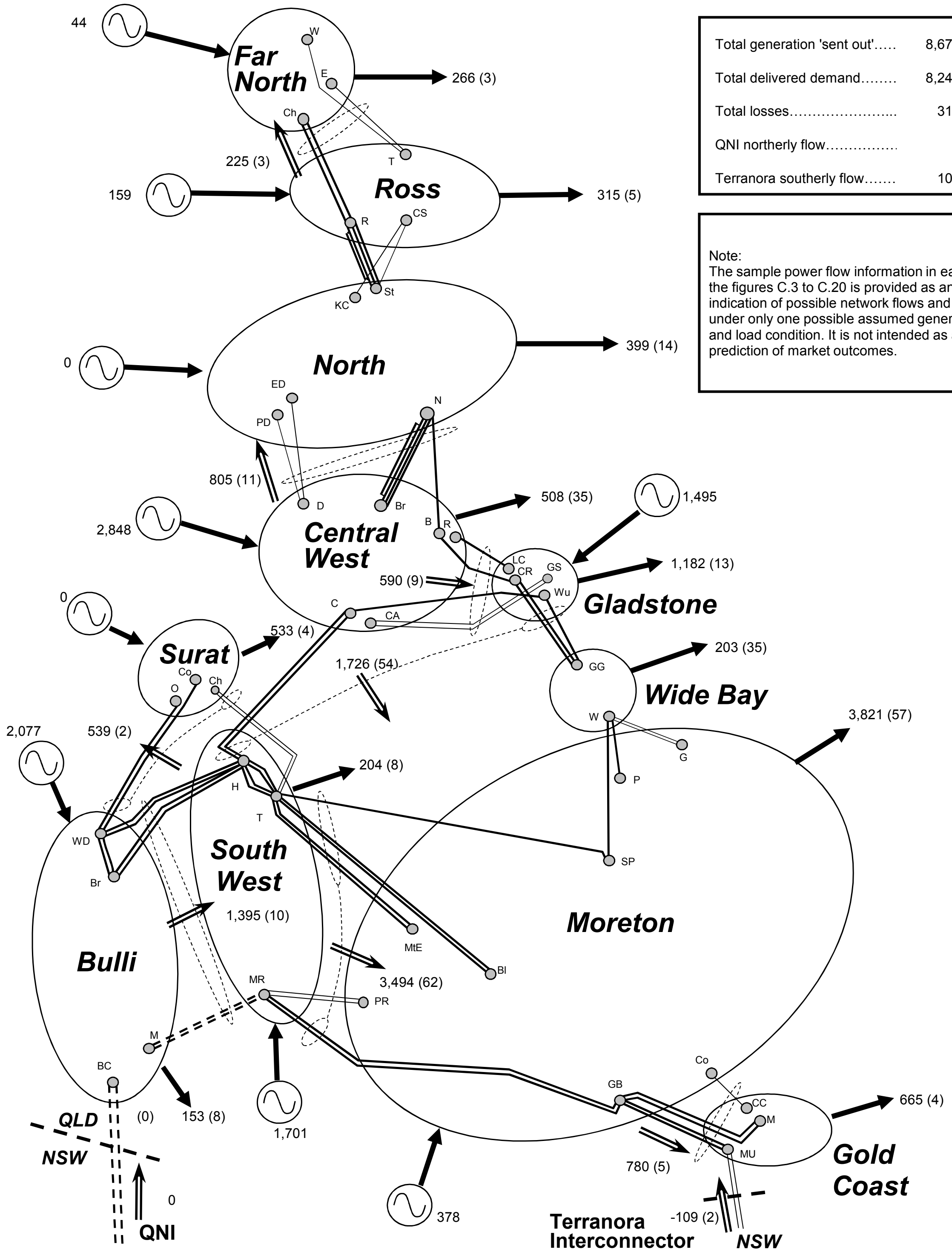
Figure C.15 Summer 2017/18 Queensland maximum demand 200MW northerly QNI flow



Total generation 'sent out'…..	8,472 MW
Total delivered demand……..	8,249 MW
Total losses……………………	314 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 2017/18 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'…..	8,672 MW
Total delivered demand……..	8,249 MW
Total losses…………………....	314 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 2017/18 Queensland maximum demand 400MW southerly QNI flow

Total generation 'sent out'.....	9,086 MW
Total delivered demand........	8,249 MW
Total losses........................	298 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.

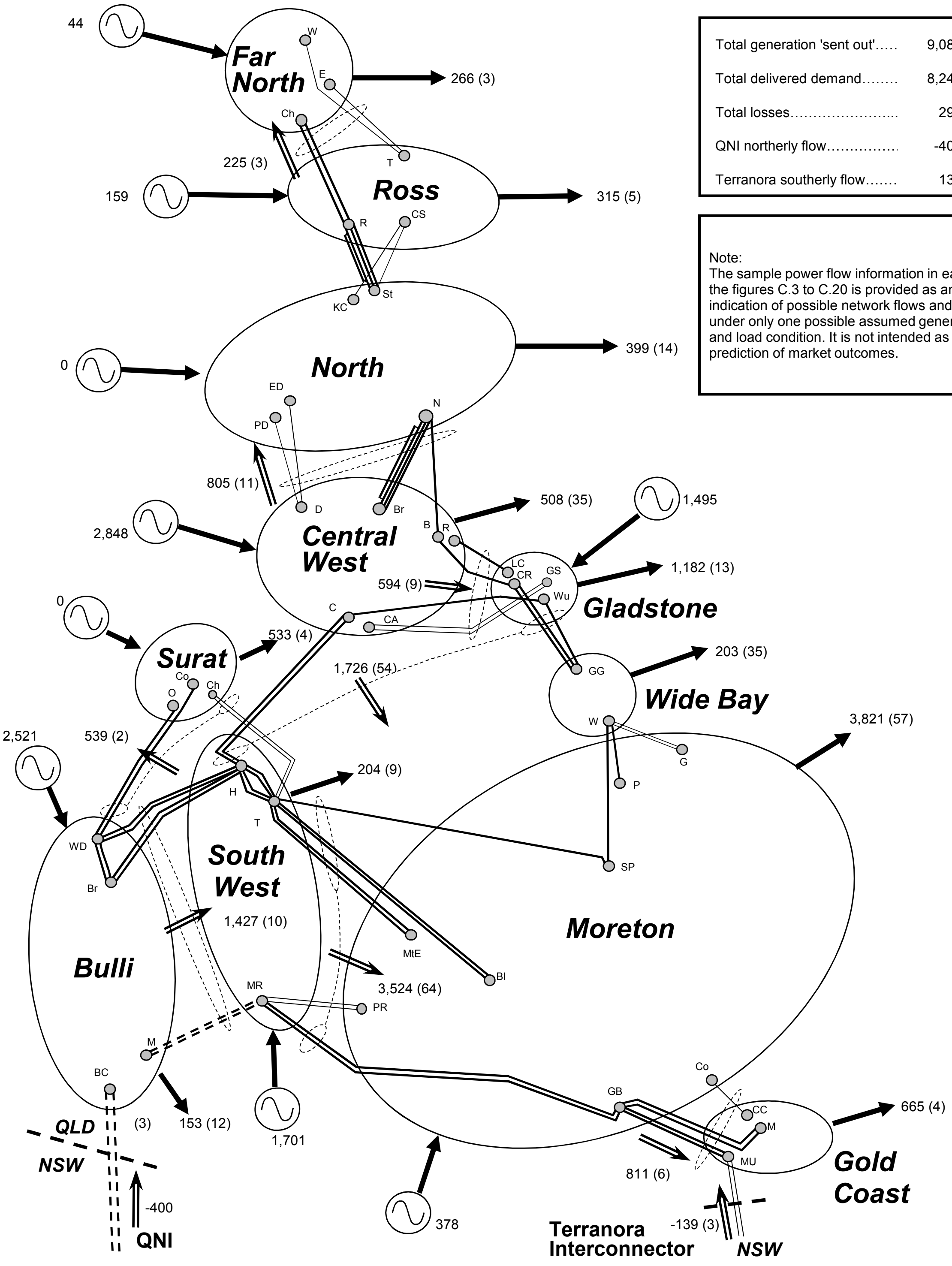
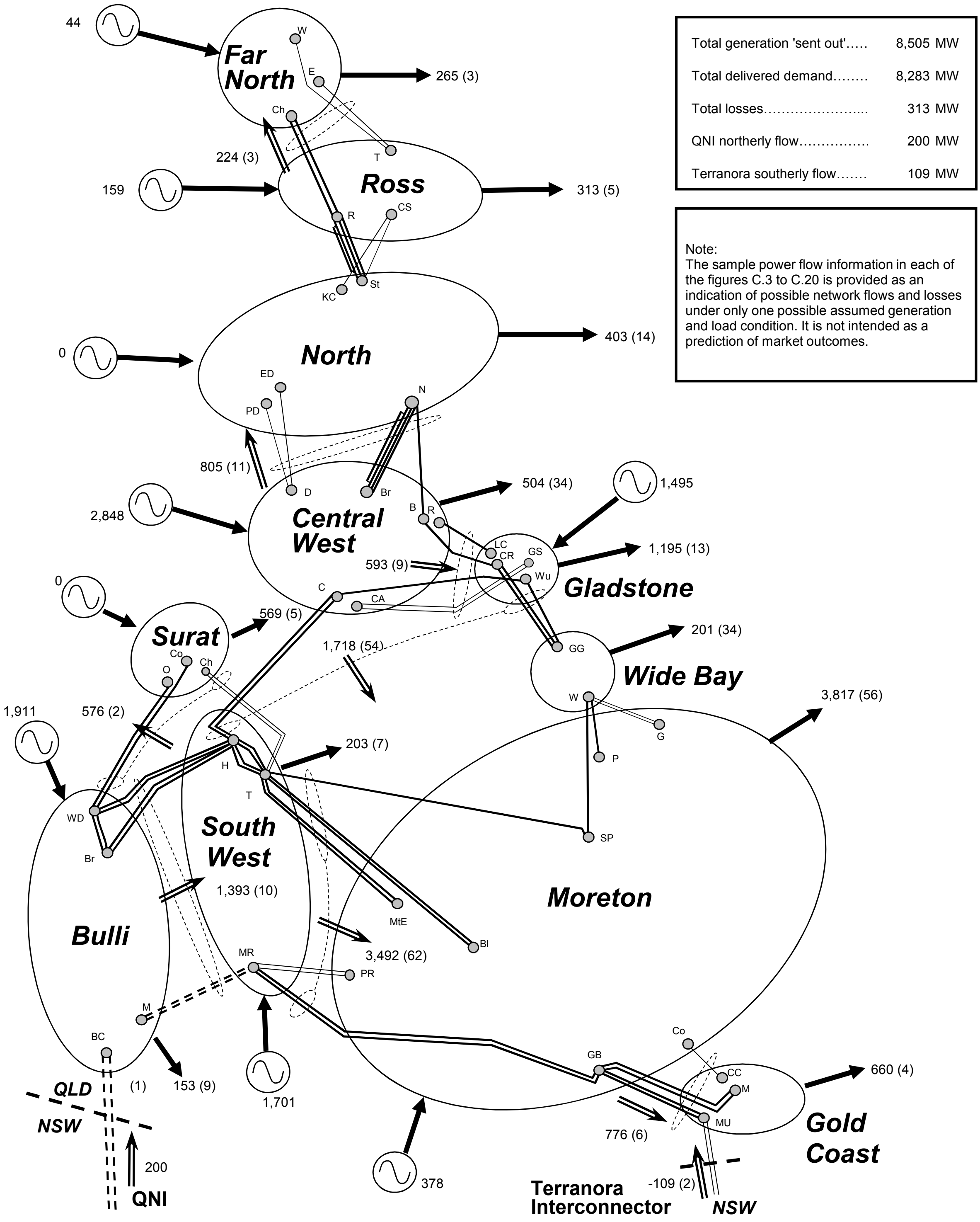


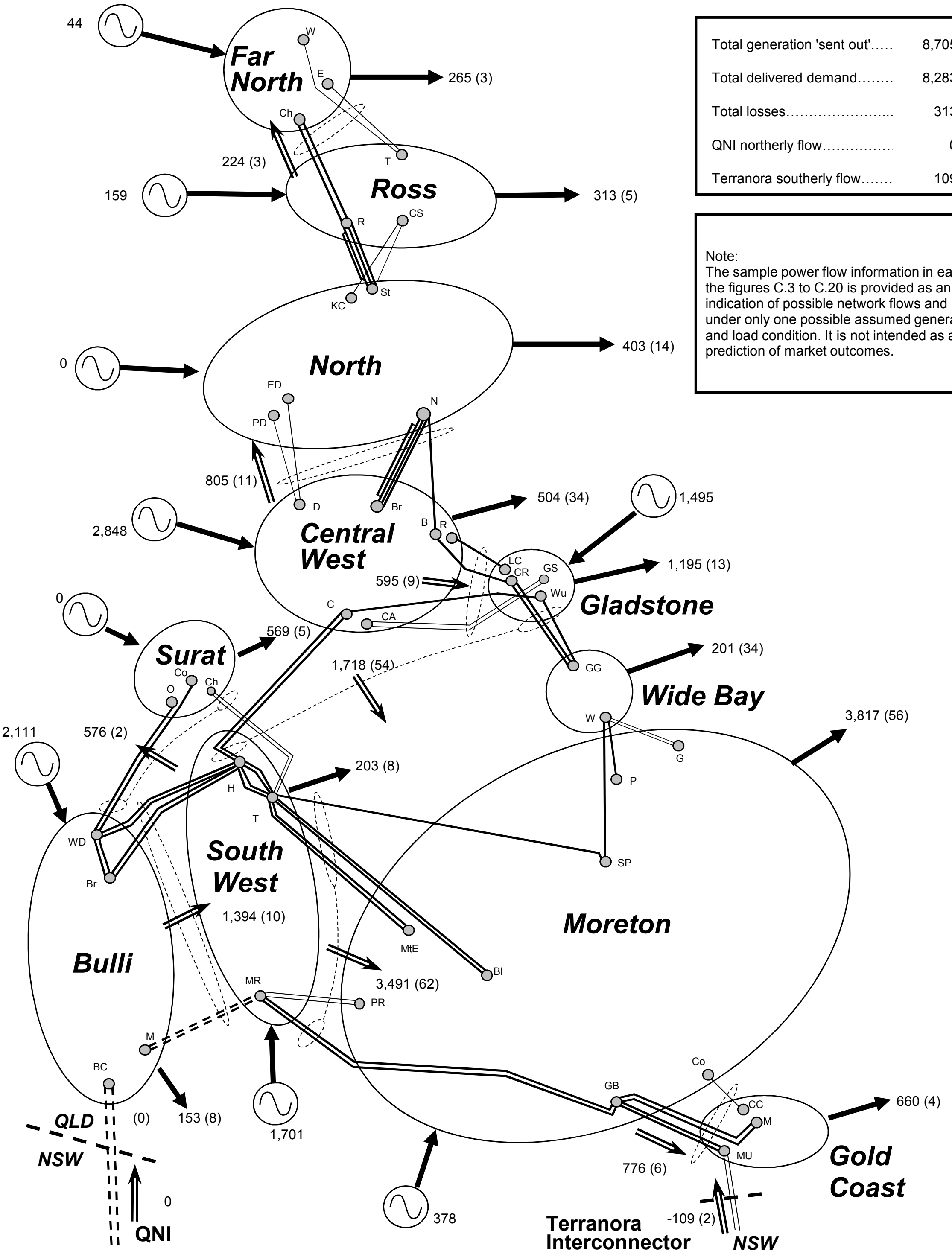
Figure C.18 Summer 2018/19 Queensland maximum demand 200MW northerly QNI flow



Total generation 'sent out'…..	8,505 MW
Total delivered demand……..	8,283 MW
Total losses…………………...	313 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.

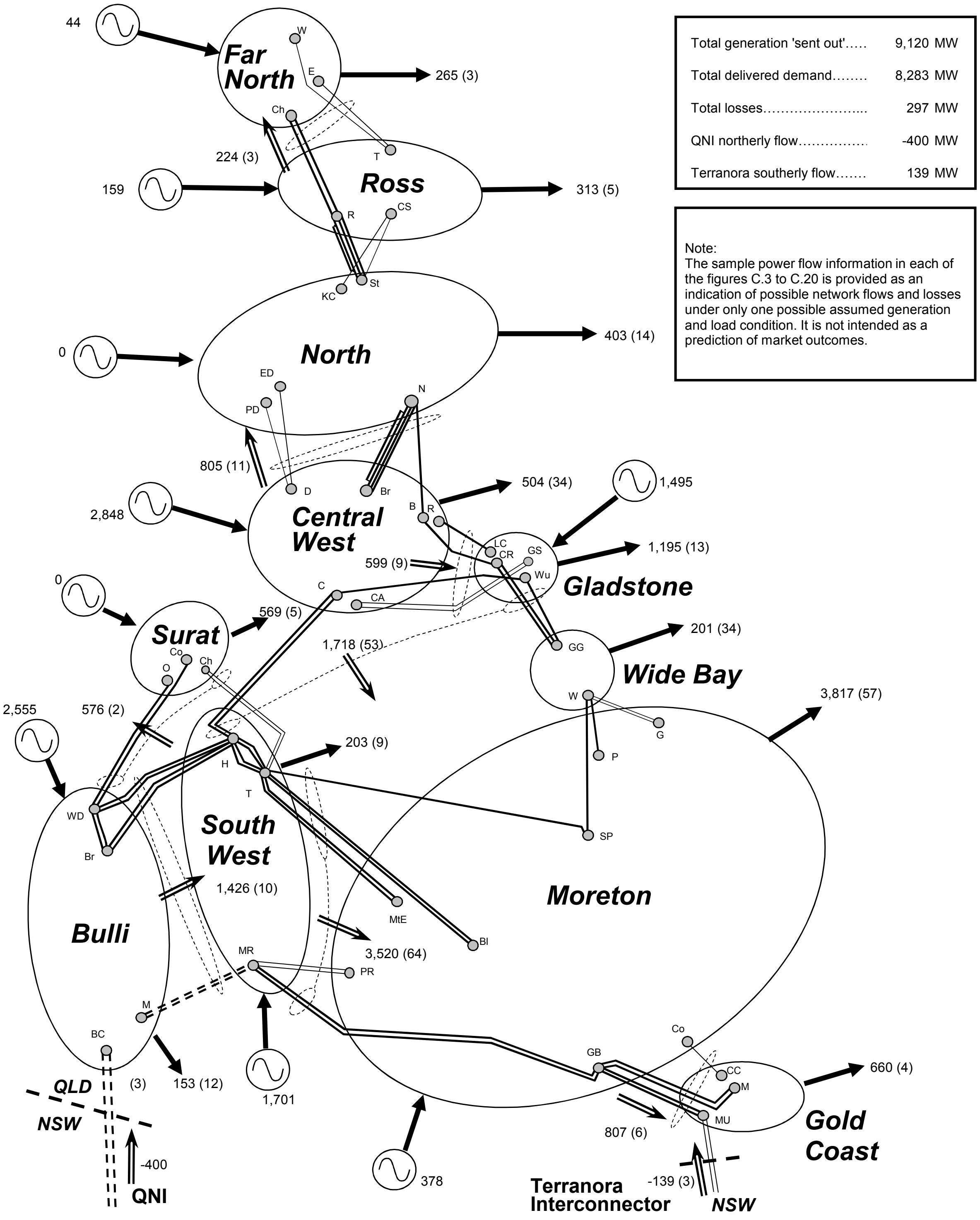
Figure C.19 Summer 2018/19 Queensland maximum demand 0MW QNI flow



Total generation 'sent out'.....	8,705 MW
Total delivered demand........	8,283 MW
Total losses........................	313 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 2018/19 Queensland maximum demand 400MW southerly QNI flow



Total generation 'sent out'…..	9,120 MW
Total delivered demand……..	8,283 MW
Total losses…………………..	297 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 40 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 36 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 short circuit currents at Powerlink Queensland's substations. The tables also show indicative minimum short circuit currents.

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 2016/17, 2017/18 and 2018/19.

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[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 reactive plant should consider the minimum short circuit current at the prospective point of connection to ensure that there is no adverse impact on power quality.

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 from a typical winter light load system condition and associated generation dispatch. The single network element that makes the greatest contribution to the symmetrical three phase short circuit fault current for each bus considered was also removed from service.

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

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[1] Swanbank E is out of service for Summer 16/17 consistent with Table 5.1. However, for the short circuit currents calculated for 2017/18 and 2018/19 Swanbank E is in-service. This was chosen on the basis of; conservative for short circuit current assessment, Stanwell maintains a Connection and Access Agreement with Powerlink, Stanwell advise that a lead-time of six to nine months is required to restart Swanbank E.

Table E.1 Indicative short circuit currents – northern Queensland – 2016/17 to 2018/19

Substation	Voltage (kV)	Plant rating (lowest kA)	Indicative minimum 3 phase (kA)	Indicative maximum short circuit currents					
				2016/17		2017/18		2018/19	
				3 phase kA	L – G kA	3 phase kA	L – G kA	3 phase kA	L – G kA
Alan Sherriff	132	40.0	4.0	12.0	12.7	12.0	12.7	12.0	12.7
Alligator Creek	132	25.0	1.9	4.5	5.9	4.5	5.9	4.5	5.9
Bollingbroke	132	40.0	2.0	2.4	1.9	2.4	1.9	2.4	1.9
Bowen North	132	40.0	1.3	2.1	2.4	2.1	2.4	2.1	2.4
Burton Downs	132	19.3	3.6	5.1	4.9	5.1	4.9	5.1	4.9
Cairns (2T)	132	25.0	0.6	5.4	7.2	5.4	7.2	5.4	7.2
Cairns (3T)	132	25.0	0.6	5.4	7.2	5.4	7.2	5.4	7.2
Cairns (4T)	132	25.0	0.6	5.4	7.3	5.4	7.3	5.4	7.3
Cardwell	132	19.3	1.0	2.8	3.0	2.8	3.0	2.8	3.0
Chalumbin	275	31.5	1.3	3.7	4.0	3.7	3.9	3.7	3.9
Chalumbin	132	31.5	2.6	6.1	7.1	6.1	7.1	6.1	7.1
Clare South	132	40.0	3.0	7.1	7.4	7.1	7.4	7.1	7.4
Collinsville North	132	31.5	2.1	7.4	8.4	7.4	8.4	7.4	8.4
Coppabella	132	31.5	2.3	2.9	3.3	2.9	3.3	2.9	3.3
Dan Gleeson (1T)	132	31.5	3.6	11.4	12.1	11.3	12.1	11.3	12.1
Dan Gleeson (2T)	132	40.0	3.6	11.3	12.0	11.3	12.0	11.3	12.0
Edmonton	132	40.0	0.8	5.0	6.1	4.9	6.1	4.9	6.1
Eagle Downs	132	40.0	1.6	4.2	4.2	4.2	4.2	4.2	4.2
El Arish	132	40.0	1.0	3.1	3.8	3.1	3.8	3.1	3.8
Garbutt	132	40.0	1.8	10.0	10.2	10.2	10.5	10.2	10.5
Goonyella Riverside	132	40.0	3.2	5.3	5.0	5.3	5.0	5.3	5.0
Ingham South	132	31.5	1.0	2.8	2.8	2.8	2.8	2.8	2.8
Innisfail	132	40.0	1.2	2.7	3.3	2.7	3.3	2.7	3.3
Invicta	132	19.3	2.5	5.1	4.6	5.1	4.6	5.1	4.6
Kamerunga	132	15.3	0.6	4.3	5.1	4.3	5.1	4.3	5.1
Kareeya	132	40.0	2.8	5.3	6.0	5.3	6.0	5.3	6.0
Kemmis	132	31.5	1.7	5.8	6.4	5.7	6.4	5.7	6.4
King Creek	132	40.0	2.1	4.4	3.8	4.4	3.8	4.4	3.8
Mackay (2T)	132	10.9	1.2	4.7	5.4	4.7	5.4	4.7	5.4
Mackay (1T & 3T)	132	10.9	1.2	4.8	5.3	4.8	5.4	4.8	5.4
Mackay Ports	132	40.0	1.7	3.5	4.1	3.5	4.1	3.5	4.1
Mindi	132	40.0	3.3	4.4	3.6	4.4	3.6	4.4	3.6
Moranbah	132	10.9	3.4	6.6	8.0	6.6	8.0	6.6	8.0

Table E.1 Indicative short circuit currents – northern Queensland – 2016/17 to 2018/19 *(continued)*

Substation	Voltage (kV)	Plant rating (lowest kA)	Indicative minimum 3 phase (kA)	Indicative maximum short circuit currents					
				2016/17		2017/18		2018/19	
				3 phase kA	L – G kA	3 phase kA	L – G kA	3 phase kA	L – G kA
Moranbah South	132	31.5	3.4	5.0	4.8	5.0	4.8	5.0	4.8
Mt McLaren	132	31.5	1.6	2.0	2.1	2.0	2.1	2.0	2.1
Nebo	275	31.5	3.9	9.4	9.9	9.3	9.9	9.3	9.8
Nebo	132	15.3	6.2	12.7	14.8	12.7	14.8	12.7	14.7
Newlands	132	25.0	1.3	3.3	3.8	3.3	3.8	3.3	3.8
North Goonyella	132	20.0	3.0	4.1	3.5	4.1	3.5	4.1	3.5
Oonooie	132	31.5	1.5	3.1	3.7	3.1	3.7	3.1	3.7
Peak Downs	132	31.5	1.7	3.9	3.5	3.9	3.5	3.9	3.5
Pioneer Valley	132	31.5	3.6	7.0	7.7	6.9	7.8	6.9	7.8
Proserpine	132	40.0	1.4	2.6	3.2	2.6	3.2	2.6	3.2
Ross	275	31.5	2.5	7.1	8.1	7.1	8.2	7.1	8.1
Ross	132	31.5	4.4	15.2	17.6	15.2	17.9	15.1	17.6
Stony Creek	132	40.0	1.2	3.4	3.4	3.4	3.4	3.4	3.4
Strathmore	275	31.5	3.0	7.8	8.3	7.7	8.3	7.7	8.3
Strathmore	132	40.0	2.3	8.2	9.6	8.2	9.6	8.2	9.6
Townsville East	132	40.0	1.5	11.6	11.6	11.6	11.7	11.6	11.6
Townsville South	132	20.0	4.0	15.1	18.6	15.1	18.8	15.0	18.6
Townsville PS Switchyard	132	31.5	2.5	9.8	10.5	9.8	10.5	9.8	10.5
Tully	132	31.5	1.9	3.7	4.0	3.7	4.0	3.7	4.0
Turkinje	132	20.0	1.2	2.6	3.0	2.6	3.0	2.6	3.0
Wandoo	132	31.5	3.4	4.5	3.1	4.4	3.3	4.4	3.3
Woree (1T)	275	40.0	0.9	2.6	3.0	2.6	3.0	2.6	3.0
Woree (2T)	275	40.0	0.9	2.6	3.0	2.6	3.0	2.6	3.0
Woree	132	40.0	2.4	5.6	7.7	5.6	7.7	5.6	7.7
Wotonga	132	40.0	1.7	5.5	6.5	5.5	6.5	5.5	6.5
Yabulu South	132	40.0	3.8	11.3	11.2	11.3	11.2	11.3	11.2

Table E.2 Indicative short circuit currents – central Queensland – 2016/17 to 2018/19

Substation	Voltage (kV)	Plant rating (lowest kA)	Indicative minimum 3 phase (kA)	Indicative maximum short circuit currents					
				2016/17		2017/18		2018/19	
				3 phase kA	L – G kA	3 phase kA	L – G kA	3 phase kA	L – G kA
Baralaba	132	15.3	1.5	4.2	3.7	4.7	4.0	4.1	3.5
Biloela	132	20.0	1.1	7.3	7.6	7.4	7.7	7.8	8.1
Blackwater	132	10.9	3.4	5.5	6.8	5.7	6.9	5.2	6.5
Bluff	132	40.0	2.3	3.4	4.2	3.4	4.2	3.2	4.1
Bouldercombe	275	31.5	9.0	19.7	19.5	19.7	19.5	19.7	19.5
Bouldercombe	132	21.8	4.7	14.5	16.8	14.5	16.8	14.5	16.8
Broadsound	275	31.5	4.8	11.2	8.6	11.2	8.8	11.2	8.7
Callemondah	132	31.5	6.9	24.1	26.3	23.8	26.1	22.0	24.6
Callide A	132	11.0	1.1	10.1	10.8	10.2	10.9	10.2	10.9
Calliope River	275	40.0	9.7	21.0	23.8	20.9	23.7	20.6	23.5
Calliope River	132	40.0	17.1	26.9	31.9	26.6	31.6	24.7	29.7
Calvale	275	31.5	10.0	23.7	26.0	23.7	26.0	23.2	25.7
Calvale	132	31.5	1.1	10.2	10.9	10.2	11.0	8.4	9.2
Dingo	132	31.5	1.6	2.6	2.8	2.7	2.9	2.7	2.9
Duaringa	132	40.0	1.3	2.1	2.7	2.1	2.8	1.3	1.8
Dysart	132	10.9	1.9	4.4	5.1	4.4	5.1	4.4	5.0
Egans Hill	132	25.0	1.6	8.3	8.2	8.3	8.2	8.3	8.2
Gladstone PS	275	40.0	10.2	19.5	21.7	19.5	21.6	19.2	21.4
Gladstone PS	132	40.0	17.0	23.3	26.3	23.1	26.1	21.7	24.9
Gladstone South	132	40.0	9.9	18.7	19.1	18.2	18.8	15.9	16.9
Grantleigh	132	31.5	2.3	2.7	2.8	2.7	2.8	2.7	2.8
Gregory	132	31.5	6.2	8.7	10.0	8.7	10.1	8.5	9.8
Larcom Creek	275	40.0	3.4	15.4	15.3	15.4	15.3	15.3	15.2
Larcom Creek	132	40.0	4.5	12.3	13.8	12.3	13.8	12.3	13.8
Lilyvale	275	31.5	2.8	5.6	5.6	5.6	5.6	5.5	5.5
Lilyvale	132	25.0	5.5	9.1	10.8	9.2	10.9	8.8	10.6
Moura	132	12.3	1.2	2.9	3.0	4.0	4.3	3.9	4.2
Norwich Park	132	31.5	1.4	3.5	2.6	3.5	2.6	3.5	2.6
Pandoin	132	40.0	1.4	7.0	6.2	7.0	6.3	7.0	6.3
Raglan	275	40.0	4.4	11.9	10.4	11.8	10.4	11.8	10.4
Rockhampton (1T)	132	10.9	4.6	6.5	6.4	6.3	6.4	6.3	6.4
Rockhampton (5T)	132	10.9	4.7	6.3	6.2	6.5	6.2	6.5	6.2
Rocklands	132	31.5	5.6	7.7	6.6	7.7	6.6	7.7	6.6

Table E.2 Indicative short circuit currents – central Queensland – 2016/17 to 2018/19 *(continued)*

Substation	Voltage (kV)	Plant rating (lowest kA)	Indicative minimum 3 phase (kA)	Indicative maximum short circuit currents					
				2016/17		2017/18		2018/19	
				3 phase kA	L – G kA	3 phase kA	L – G kA	3 phase kA	L – G kA
Stanwell	275	31.5	10.1	22.3	24.1	22.3	24.1	22.3	24
Stanwell	132	31.5	4.5	6.0	6.4	6.0	6.5	6.0	6.5
Wurdong	275	31.5	7.2	16.9	16.8	16.9	16.7	16.7	16.6
Wycarbah	132	40.0	3.6	4.5	5.4	4.5	5.4	4.5	5.4
Yarwun	132	40.0	5.3	12.9	14.9	12.9	14.9	12.9	14.9

Table E.3 Indicative short circuit currents – southern Queensland – 2016/17 to 2018/19

Substation	Voltage (kV)	Plant rating (lowest kA)	Indicative minimum 3 phase (kA)	Indicative maximum short circuit currents					
				2016/17		2017/18		2018/19	
				3 phase kA	L – G kA	3 phase kA	L – G kA	3 phase kA	L – G kA
Abermain	275	40.0	7.0	18.0	18.6	18.0	18.6	18.0	18.6
Abermain	110	31.5	10.9	21.4	25.2	21.3	25.2	21.3	25.2
Algester	110	40.0	13.0	21.5	21.2	21.5	21.2	21.5	21.2
Ashgrove West	110	26.3	12.5	19.1	20.0	19.1	20.0	19.1	20.0
Belmont	275	31.5	8.5	16.8	18.5	16.8	18.5	16.8	18.5
Belmont	110	37.4	17.7	29.7	37.0	29.7	37.0	29.7	37.0
Blackwall	275	37.0	9.8	22.0	23.9	22.0	23.9	22.0	23.9
Blackstone	275	40.0	9.1	20.9	23.2	20.9	23.2	20.9	23.2
Blackstone	110	40.0	14.9	25.4	29.1	25.2	28.9	25.2	28.9
Blythdale	132	40.0	2.6	4.2	5.2	4.2	5.2	4.2	5.2
Braemar	330	50.0	7.9	23.0	25.2	23.0	25.1	23.0	25.1
Braemar (East)	275	40.0	8.5	33.4	38.9	26.4	30.8	26.4	30.8
Braemar (West)	275	40.0	6.8	-	-	26.3	29.3	26.3	29.3
Bulli Creek	330	50.0	8.9	18.1	14.3	18.1	14.3	18.1	14.3
Bulli Creek	132	40.0	3.5	3.8	4.3	3.8	4.3	3.8	4.3
Bundamba	110	40.0	8.4	17.2	16.6	17.2	16.6	17.2	16.6
Chinchilla	132	25.0	4.8	8.0	7.8	7.9	7.8	7.9	7.8
Clifford Creek	132	40.0	3.9	5.7	5.2	5.7	5.2	5.7	5.2
Columboola	275	40.0	5.6	12.8	11.9	12.2	11.6	12.2	11.6
Columboola	132	25.0	7.0	16.3	18.4	16.1	18.2	16.1	18.2
Condabri Central	132	40.0	5.2	9.0	6.7	8.9	6.6	8.9	6.6
Condabri North	132	40.0	7.4	13.2	12.1	13.1	12.1	13.1	12.1
Condabri South	132	40.0	4.2	6.6	4.4	6.5	4.4	6.5	4.4
Dinoun South	132	40.0	4.7	6.5	6.8	6.5	6.8	6.5	6.8
Eurombah (1T)	275	40.0	1.3	4.3	4.6	4.3	4.5	4.3	4.5
Eurombah (2T)	275	40.0	1.3	4.3	4.6	4.3	4.5	4.3	4.5
Eurombah	132	40.0	4.3	6.9	8.5	6.8	8.4	6.8	8.4
Fairview	132	40.0	2.9	4.0	5.1	4.0	5.1	4.0	5.1
Fairview South	132	40.0	3.7	5.2	6.6	5.2	6.6	5.2	6.6
Gin Gin	275	14.5	6.5	10.9	10.4	10.9	10.1	10.9	10.0
Gin Gin	132	20.0	6.8	12.6	13.0	12.8	13.9	12.8	13.9
Goodna	275	40.0	6.2	16.0	16.0	16.0	16.0	16.0	16.0
Goodna	110	40.0	14.4	25.3	27.5	25.3	27.5	25.3	27.5

Table E.3 Indicative short circuit currents – southern Queensland – 2016/17 to 2018/19 *(continued)*

Substation	Voltage (kV)	Plant rating (lowest kA)	Indicative minimum 3 phase (kA)	Indicative maximum short circuit currents					
				2016/17		2017/18		2018/19	
				3 phase kA	L – G kA	3 phase kA	L – G kA	3 phase kA	L – G kA
Greenbank	275	40.0	9.1	20.2	22.4	20.2	22.4	20.2	22.4
Halys	275	50.0	13.1	31.4	26.0	31.3	26.0	31.3	26.0
Kumbarilla Park (1T)	275	40.0	1.7	19.0	17.7	16.5	15.9	16.5	15.9
Kumbarilla Park (2T)	275	40.0	1.7	19.0	17.7	16.5	15.9	16.5	15.9
Kumbarilla Park	132	40.0	6.2	13.8	15.8	13.2	15.2	13.2	15.2
Loganlea	275	40.0	6.8	14.8	15.4	14.8	15.4	14.8	15.4
Loganlea	110	25.0	13.7	22.8	27.4	22.8	27.4	22.8	27.4
Middle Ridge (4T)	330	50.0	4.1	12.5	12.2	12.5	12.3	12.5	12.3
Middle Ridge (5T)	330	50.0	4.1	12.9	12.6	12.9	12.7	12.9	12.7
Middle Ridge	275	31.5	8.6	17.9	18.1	17.9	18.3	17.9	18.3
Middle Ridge	110	18.3	9.7	20.3	24.2	20.3	24.8	20.3	24.9
Millmerran Switchyard	330	40.0	9.1	18.3	19.6	18.3	19.6	18.3	19.6
Molendinar (1T)	275	40.0	2.4	8.2	8.1	8.2	8.1	8.2	8.1
Molendinar (2T)	275	40.0	2.4	8.2	8.1	8.2	8.1	8.2	8.1
Molendinar	110	40.0	12.1	20.0	25.3	20.0	25.2	20.0	25.2
Mt England	275	31.5	9.5	22.4	22.7	22.4	22.7	22.4	22.7
Mudgeeraba	275	31.5	5.0	9.4	9.5	9.4	9.4	9.4	9.4
Mudgeeraba	110	25.0	12.7	18.7	22.8	18.7	23.0	18.7	23.0
Murarrie (2T)	275	40.0	2.6	13.0	13.4	13.0	13.4	13.0	13.4
Murarrie (3T)	275	40.0	2.6	13.0	13.5	13.0	13.5	13.0	13.5
Murarrie	110	40.0	15.0	24.2	29.2	24.2	29.2	24.2	29.2
Oakey GT PS	110	31.5	5.3	10.8	12.0	10.8	12.0	10.8	12.0
Oakey	110	40.0	1.2	10.1	10.0	10.1	10.0	10.1	10.0
Orana	275	40.0	4.0	15.5	14.1	14.6	13.6	14.6	13.6
Palmwoods	275	31.5	3.7	8.4	8.8	8.4	8.9	8.4	8.9
Palmwoods	132	21.9	8.9	13.0	15.5	13.0	15.7	13.0	15.7
Palmwoods (7T)	110	40.0	2.8	7.2	7.5	7.2	7.6	7.2	7.6
Palmwoods (8T)	110	40.0	2.8	7.2	7.5	7.2	7.6	7.2	7.6
Redbank Plains	110	31.5	10.5	21.3	20.8	21.3	20.8	21.3	20.8
Richlands	110	40.0	12.4	22.0	22.7	22.0	22.7	22.0	22.7
Rocklea (1T)	275	31.5	2.6	13.1	12.3	13.1	12.3	13.1	12.3
Rocklea (2T)	275	31.5	2.6	8.7	8.4	8.7	8.4	8.7	8.4

Table E.3 Indicative short circuit currents – southern Queensland – 2016/17 to 2018/19 *(continued)*

Substation	Voltage (kV)	Plant rating (lowest kA)	Indicative minimum 3 phase (kA)	Indicative maximum short circuit currents					
				2016/17		2017/18		2018/19	
				3 phase kA	L – G kA	3 phase kA	L – G kA	3 phase kA	L – G kA
Rocklea	110	31.5	14.5	24.9	28.7	24.8	28.7	24.8	28.7
Runcorn	110	40.0	9.5	19.3	19.6	19.3	19.6	19.3	19.6
South Pine	275	31.5	8.9	18.5	21.1	18.5	21.1	18.5	21.1
South Pine (West)	110	40.0	11.3	20.4	23.5	20.4	23.5	20.4	23.5
South Pine (East)	110	40.0	13.2	21.4	27.5	21.4	27.5	21.4	27.5
Sumner	110	40.0	10.1	20.6	20.2	20.6	20.2	20.6	20.2
Swanbank E	275	40.0	9.8	20.6	22.7	20.6	22.7	20.6	22.7
Tangkam	110	31.5	4.2	12.8	12.0	12.8	12.1	12.8	12.1
Tarong (1)	275	31.5	13.5	32.9	34.6	32.9	34.6	32.9	34.6
Tarong (1T)	132	25.0	1.2	5.8	6.0	5.8	6.0	5.8	6.0
Tarong (4T)	132	25.0	1.2	5.8	6.0	5.8	6.0	5.8	6.0
Tarong	66	40.0	7.0	15.0	16.2	15.0	16.2	15.0	16.2
Teebar Creek	275	40.0	3.4	7.3	7.2	7.3	7.2	7.3	7.2
Teebar Creek	132	40.0	6.3	10.1	11.2	10.1	11.2	10.1	11.2
Tennyson	110	40.0	1.9	16.2	16.4	16.2	16.4	16.2	16.4
Upper Kedron	110	40.0	13.3	21.2	18.7	21.1	18.7	21.1	18.7
Wandoan South	275	40.0	3.8	7.2	7.9	7.0	7.7	7.0	7.7
Wandoan South	132	40.0	4.9	8.7	11.1	8.6	11.0	8.6	11.0
West Darra	110	40.0	14.9	24.8	23.8	24.8	23.8	24.8	23.8
Western Downs	275	40.0	12.0	26.8	26.2	24.1	24.2	24.1	24.2
Woolooga	275	31.5	5.7	9.6	10.8	9.6	10.8	9.6	10.8
Woolooga	132	20.0	8.0	13.0	15.5	13.1	15.5	13.0	15.5
Yuleba North	275	40.0	3.8	5.8	6.4	5.7	6.3	5.7	6.3
Yuleba North	132	40.0	4.7	7.8	9.4	7.7	9.3	7.7	9.3

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
APLNG	Australia Pacific Liquefied Natural Gas
APR	Annual Planning Report
BSL	Boyne Smelters Limited
CQ	Central Queensland
CSM	Coal Seam Methane
DNSP	Distribution Network Service Provider
ESOO	Electricity Statement of Opportunity
FNQ	Far North Queensland
GLNG	Gladstone Liquefied Natural Gas
GT	Gas Turbine
GWh	Gigawatt hour
JPB	Jurisdictional Planning Body
kA	Kiloampere
kV	Kilovolt
LNG	Liquefied natural gas
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
SCR	Short Circuit Ratio
SEQ	South East Queensland
SQ	South Queensland
SVC	Static VAr Compensator
SWQ	South West Queensland
TAPR	Transmission Annual Planning Report
TNSP	Transmission Network Service Provider
WD	Weather dependent

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