Workshop on
SPECIAL PROTECTION SYSTEMS
for Transmission Operations and Emergencies

for
Afghanistan, Kazakhstan,
Kyrgyzstan, Tajikistan
and Uzbekistan

ALMATY, KAZAKHSTAN
February 18-20, 2009

USAID FROM THE AMERICAN PEOPLE

USEA United States Energy Association

BONNEVILLE POWER ADMINISTRATION

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FOR

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WORKSHOP ON
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AFGHANISTAN, KAZAKHSTAN, KYRGYZSTAN, TAJIKISTAN,TURKMENISTAN AND UZBEKISTAN

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Managed by
UNITED STATES ENERGY ASSOCIATION (USEA)

Funded by
THE U.S. AGENCY FOR INTERNATIONAL DEVELOPMENT (USAID)

OBJECTIVE: To provide detailed information on Special Protection Systems (SPS) used in Transmission Systems to mitigate emergencies and other extraordinary situations.

This workshop will focus on "Special Protection Systems" (SPS). SPS are automatic protection systems designed to detect abnormal, emergency or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows.

This workshop will also focus on (a) underfrequency or undervoltage load shedding; (b) fault conditions that must be isolated; and (c) out-of-step relaying; which, are not usually designed as an integral part of an SPS.

Note: Special Protection Systems (SPS) will often be referred to as Remedial Action Schemes (RAS) by the Bonneville Power Administration. The use of the term RAS in place of SPS by BPA is done so to maintain consistency with the standards set by their electricity coordinator, the Western Electricity Coordinating Council (WECC).

Participants:

Afghanistan

His Excellency, Dr. M.J. Shams; Minister of Economy; Chairman of the Inter-Ministerial Commission for Energy (ICE); Chairman of the DABS Board of Directors, and Chief Executive Officer (CEO) of Da Afghanistan Breshna Shirkat (DABS), jpsjams@bluewin.ch
Engineer Saheb Gul Afridi (DABM Head of Generation for Naghlu, Mahipar and Sarobi)
Engineer Habibulah Hamdard, K.E.D.
Engineer Mohammad Aman Mukhles (DABM Transmission Specialist, Mazar-e-Sharif Breshna)
Ridi Gull Khan Paiman (DABM President of Nangarhar Electricity Department)
Mohammad (Moe) Aslam, PE PMP, Louis Berger Group - Black and Veatch Afghanistan Infrastructure & Rehabilitation Program (AIRP)
Abdul Rasool Wardak, USAID/Afghanistan

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TUESDAY, FEBRUARY 17

19.00 USEA hosted Welcome Dinner (*Hotel Restaurant)*

WEDNESDAY, FEBRUARY 18

9.00-9.15 **WELCOME AND OVERVIEW OF WORKSHOP-**
JOHN HAMMOND, PROGRAM MANAGER, USEA

9.15-10.30 **OVERVIEW OF USAID REGIONAL PROJECTS-REMAP II**

10.30-10.45 **Tea Break**

10.45-12.00 **CROSS-BORDER POWER TRADE AND REGIONAL POWER POOL MANAGEMENT**
BPA

- Columbia River Treaty (Between U.S. and Canada)
- Pacific Northwest Coordination Agreement
- Northwest Power Pool

Eskom

- Southern African Power Pool
- Cross-Border Power Trade and Treaties

12.30-13.30 **Lunch**

13.30-14.30 TEN MINUTE PRESENTATIONS ON TRANSMISSION SYSTEMS PROTECTION SCHEMES IN AFGHANISTAN, KAZAKHSTAN, KYGYZTAN, TAJIKISTAN, TURKMENISTAN, UZBEKISTAN AND CDC ENERGIA - PRESENTATIONS BY PARTICIPANTS AND DISCUSSION

- Afghanistan
- Kazakhstan
- Kyrgyzstan
- Tajikistan
- Turkmenistan
- Uzbekistan

14.30-15.30 CDC Presentation on Reliability Issues with Parallel operation of the Power System between Afghanistan and Central Asia

15.30-15.45 Tea Break

15.45-16.45 ESKOM SPECIAL PROTECTION SYSTEMS (SPS) -OVERVIEW- *TERESA CAROLIN*

- Function of SPS
- Components of SPS
- Actions of SPS
- Consistent Requirements and Rules
- Overview of Transmission Coordinators and Organizations

16.45-17.45 BPA SPECIAL PROTECTION SYSTEMS (SPS) -OVERVIEW- *TOM ROSEBURG AND DAN WESTON*

- Overview of the BPA transmission system
- Overview of Transmission Reliability Coordinators and Regulating Organizations (WECC, NERC, FERC)
- BPA relationship to WECC, NERC, FERC
- Consistent Requirements and Rules for SPS

THURSDAY, FEBRUARY 19

9.00-10.30 REMEDIAL ACTION SCHEMES (RAS) -*DAN WESTON*

- What, Why, Who, Where of RAS
- Goals of RAS
- Localized versus system-wide RAS
- Reasons for RAS
- Thermal overload RAS
- Voltage Stability RAS
- Transient Stability RAS
- Import vs. Export of power
- Islanding

- The study process – finding the potential problems
- Reliability – WECC guidelines
- RAS Design Criteria – No single point of failure – WECC guidelines
- Peer Review of designs – WECC RAS RS
- Testing
- Record-keeping – Disturbance logging, analysis and reporting
- Monitoring/Alarming
- Arming – manual and automatic
- Dispatching

10.30-10.50 Tea break

10.50-12.30 Typical RAS system components

- Central RAS Controllers
- Inputs
- Outputs
- Communications system

12.30-13.30 Lunch

13.30-17.00 REMEDIAL ACTION SCHEMES (continued)-*DAN WESTON*

RAS Programmable Logic Controller

- Triple Redundant
- Fault Tolerant

RAS Inputs

- Line Loss Detection
- Generation Loss Detection
- Power, Voltage, Current
- Power Rate Relays
- Other RAS
- Parallel Systems

15.30-15.50 Tea break

15.50-17.00 RAS Outputs

- Generation Dropping
- Braking Resistors
- Reactive Switching
- Load Tripping
- Intertie Separation

FRIDAY, FEBRUARY 20

9.00-10.30 **SPECIAL PROTECTION SYSTEMS- USE OF RELAYS AND OTHER EQUIPMENT- *TOM ROSEBERG***

Types of Faults:

- Under frequency and under voltage load shedding
- Dead bus clearing and auto restoration
- Typical BPA substation configurations;
    - main bus/auxiliary bus,
    - ring bus,
    - 1 ½ breaker bus

Fault Calculation

Methods for detecting faults

10.30-10.50 **Tea break**

10.50-12.00 **Transmission Protection Equipment**

- Typical protective relaying schemes used in the BPA system
- Allowable fault clearing times
- Backup protection; Redundant systems, over lapping zones, breaker failure protection, etc.
- Allowable clearing for backup schemes
- Reclosing

12.00-13.30 **Lunch**

13.30-15.40 **PROTECTION (continued) AND COMMUNICATIONS SYSTEM'S RELAYS**

- Single Pole Switching
- Series Compensation
- Communications schemes for protective relays

15.40-16.00 **Tea break**

16.00-17.00 **ROUND TABLE DISCUSSION: ADDITIONAL CONSIDERATIONS NOT USUALLY ADDRESSED BY SPECIAL PROTECTION SYSTEMS**

- Wrap-up Discussion
- Discussion of Future Activities
- Evaluation of Workshop

Reliability issues in the course of organizing parallel operation of the Afghanistan Transmission System with the Central Asia Interconnected Power System (CA IPS)

Prepared by CDC "Energy"

Tashkent, Uzbekistan

Transmission Systems Reliability Workshop for transmission systems experts from Afghanistan, Tajikistan, Turkmenistan and Uzbekistan

In the world practice operational reliability of large power interconnections was provided at the account of:

• implementation of N-1 reliability principle which requires such reservation when outage of any element of a power system does not result in power supply interruption;

• introduction of specialized means of emergency control aimed to decrease failure probability and failure development.

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The first approach is current with Western power interconnected utilities. It involves considerable funds to be invested in construction of transmission networks to ensure sufficient reservation.

Is it sufficient to ensure adequate operation reliability of the entire interconnection or of its parts?

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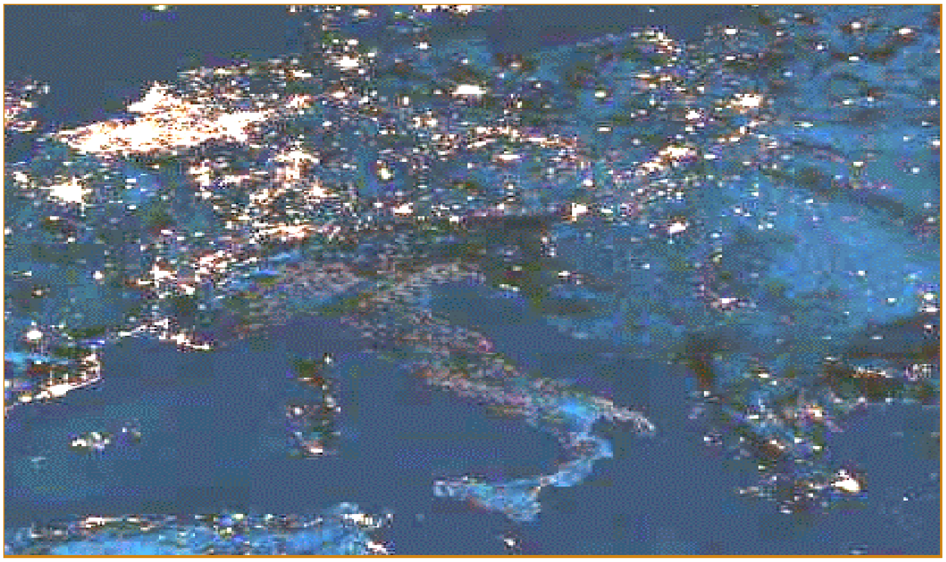

Space shot of total shut down of Italy's power system

Performance experience of power systems of Western Europe, USA, Mosenergo, where, as it turned out, degree of introduction of emergency management means is not sufficient, demonstrates:

- it is impossible to achieve guaranteed uninterrupted and failure-free operation of a power interconnection through reservation;
- human factor, delay in taking right decisions do not exclude cascading development of an incident in a power system.

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A large number of remote and isolated power interconnections (Interconnected Power Systems/IPS) operated in the territory of the former USSR.

Intersystem ties did not meet N-1 reliability principle.

That is why during integration of IPSs into Unified Power System (UPS) special attention was paid to emergency management, thus allowing:

- to reduce costs for construction of transmission networks;
- to increase reliability of UPS operation under severe conditions.

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At present formation of Afghanistan power system is in progress, including intensive construction of power network. It is planned to arrange parallel operation of Afghan power system with CA IPS, and via it with UPS of the CIS.

Same requirements and criteria applied to other participants of the CIS UPS shall be applied to Afghan power system as soon as it starts parallel operation.

Taking into consideration that CA IPS – Afghan power system interface is qualified as weak link, special attention will have to be paid to emergency management.

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Summary
of emergency management
used in the CIS power systems

Emergency management includes:

- automatic excitation control (AEC) installed on generators of electric power plants;
- relay protection of electric power networks (RP);
- emergency control automatics (ECA).

Principles for AEC and RP applied in Western and Eastern power interconnections are practically the same.

ECA principles in the CIS UPS have their specific features.

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Emergency Control Automatics is a set of devices located at electric power facilities and meant to ensure stability of a power system.

Stability – ability of a power system to support parallel operation of its elements under various disturbances.

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Steady-state stability – ability of a power system to support parallel operation under small disturbances (load start or loss, irregular fluctuations in the power system).

Transient stability – ability of a power system to support parallel operation under large disturbances (tripping of any element with 500 kV voltage, 500 kV HV-line short circuit, outage of a biggest generator or block, except unique ones, such as B-1 of Talimardjan TPS with capacity of 800 MW).

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Stability margins are rated and evaluated with stability margin factor.

Load nodes' stability margin factor

$$K_u = \frac{U_{load} - U_{cr}}{U_{load}} \cdot 100\%,$$

where U_{load} is sustained voltage in load nodes,

U_{cr} – critical voltage under which motors' stability failure occurs.

K_u under normal conditions shall not be less than 15%, under forced stress conditions – not less than 10%.

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Steady-state stability margin factor of interconnection links

$$K_p = \frac{P_{lim} - P - \Delta P}{P} \cdot 100\%,$$

where P_{lim} – transmitted power limit,

P – transmitted power via an interconnection link,

ΔP – irregular fluctuations.

K_p shall not be less than 20% under normal operating conditions, and not less than 8% under short-term post-fault conditions.

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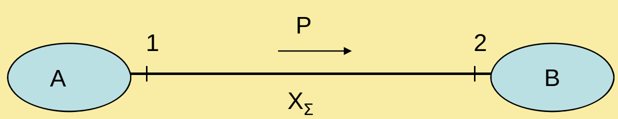
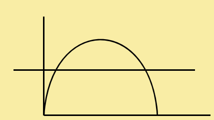


$$P = \frac{U_1 \cdot U_2}{X_\Sigma} \cdot \sin \delta_{12} = P_{lim} \cdot \sin \delta_{12}$$



If transmitted power P is close to maximum permissible one, then margin factor shall grow less.

If δ_{12} angles are less than 90º - stable operation area.

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If stability margins are violated parallel operation among parts of the power system may be disturbed, i.e. one or several parts of the power system will operate asynchronously with remaining part of the power system.

Under asynchronous operation power is not transmitted via interconnection link, thus leading to excess of power in transmitting part of the power system and its shortage in receiving part.

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By regular calculations experts with a power system should check sufficiency of steady-state stability margin under normal and maintenance conditions.

Results of the calculations should be drawn up as guidelines for a power system operator, as well as presented as a set of operating and information materials for constant automated and visual monitoring.

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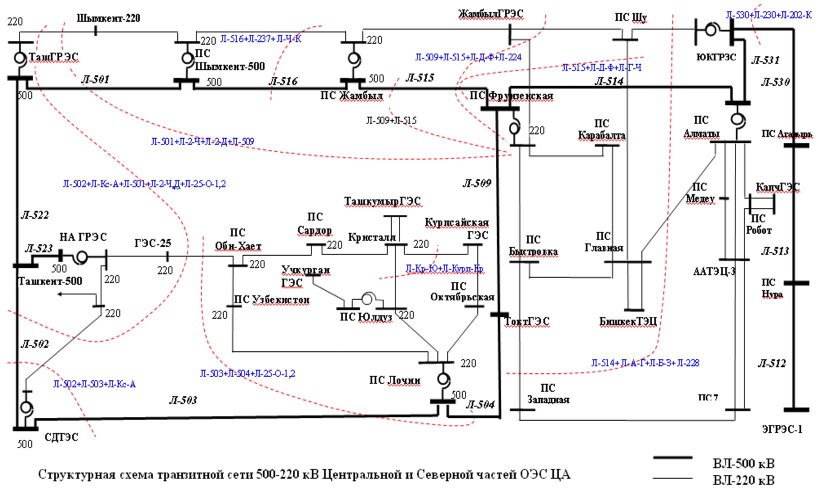

Структурная схема транзитной сети 500-220 кВ Центральной и Северной частей ОЭС ЦА

Layout of Central and Northern parts of the CA IPS showing control sections

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Fragment from "Guidelines For Stability Control Schemes for 500 kV IPS Ring under outage of L-501, L-502, L-503, L-504, L-509, L-5169, L-522, L-523. (from AAD to SDTPS)

№	Схема сети	Факторы действия	КПР в сеч	Устав-ки	Виды и объекты воздействия	Дозировка воздействия
1	2	3	4	5	6	7
1	Полная схема	Л-502	Р1	1600	ОГ ГЭС-7, (ГЭС-20) ОН ФЭУ, (ПС Шымкент)	1Г 2ст 3ст
				1850	ОГ ГЭС-7, (ГЭС-20) ОН ФЭУ, (Сев.Кырг+АЭУ ПС Шымкент)	2Г 3ст 3ст 3ст
			Р8	1250	ОГ ГЭС-31	1Г
				1500	ОГ ГЭС-31 ОН ФЭУ	2Г 2ст
			Р10	900	ОН ПС Каракуль+НБУ, (ПС Карши)	2ст
		Л-522	Р1	1600	ОГ ГЭС-7, (ГЭС-20, ГЭС-31)	1Г
					ОН ФЭУ, (ПС Шымкент)	2ст 3ст
		Л-503	Р1	1600	ОГ ГЭС-7, (ГЭС-20) ОН ФЭУ	1Г 2ст
				1850	ОГ ГЭС-7, (ГЭС-20) ОН ФЭУ, (Сев.Кырг+АЭУ)	2Г 3ст 3ст
			Р3	1800	ОГ ГЭС-31, (ГЭС-7, ГЭС-20) ОН ФЭУ	1Г 2ст
			Р6	1100	ОН ФЭУ	2ст
			Р10	900	ОН ПС Каракуль+НБУ, (ПС Карши)	2ст
		Л-504	Р2	1400	ОГ ГЭС-7, (ГЭС-20) ОН (Сев.Кырг+АЭУ)	1Г 3ст
			Р6	1100	ОН ФЭУ	2ст
2	Ремонт Л-502	Л-522	Р1	1600	ОГ ГЭС-7, (ГЭС-20, ГЭС-31) ОН ФЭУ, (ПС Шымкент)	1Г 2ст 3ст
			Р8	1250	ОГ ГЭС-31	1Г

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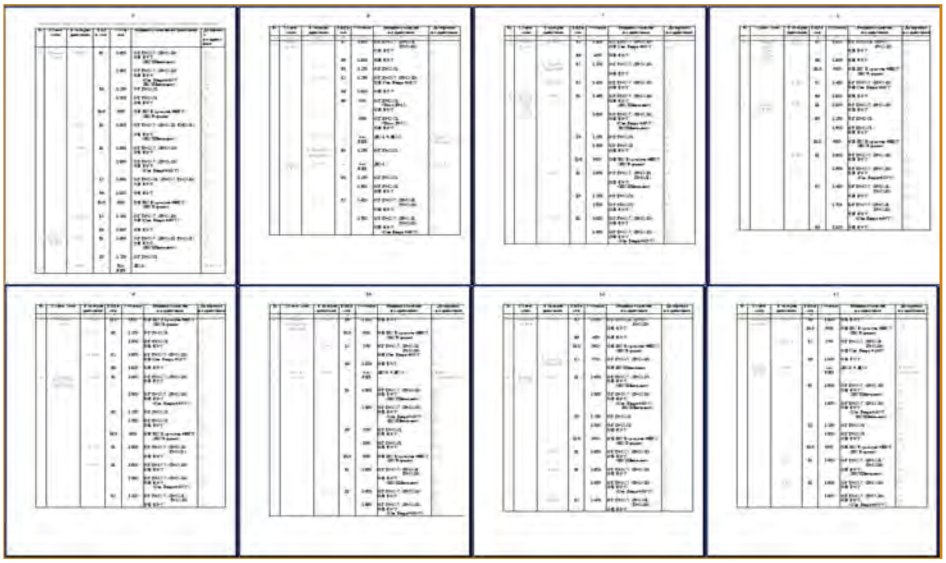

Fragments from the Guidelines for SCS of the CA IPS 500 kV ring (continued)

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As to their structure ECA devices can be:

- Decentralized or local, where control actions are formed according to local factors at various controlled facilities and transmitted to stations of their implementation with teletripping devices (e.g., node center of Novo-Agrenskaya Thermal Power Plant, Substation Khorezm and so on).
- Centralized ECA complexes where all devices of a complex are joined together with unified control logic in a single central unit. In our power system the largest complex of the kind is at Syrdaryinskaya TPS, and at a number of 500 kV substations.

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As to their functionality, ECA devices can be divided into 4 groups:

1. ECA devices designed to prevent instability (Stability Control Schemes/SCS);
2. ECA devices to prevent or eliminate asynchronous conditions (Pole Slip Protection/PSP);
3. ECA devices designed to prevent hazardous situations of frequency drop (Frequency Drop Protection/FDP) and over frequency (Over Frequency Protection/OFP);
4. ECA devices to restore normal scheme and conditions (ATE/Automatic Transfer Equipment, FAAR/Frequency Actuated Automatic Reclosing, GAS/Generator Automatic Start).

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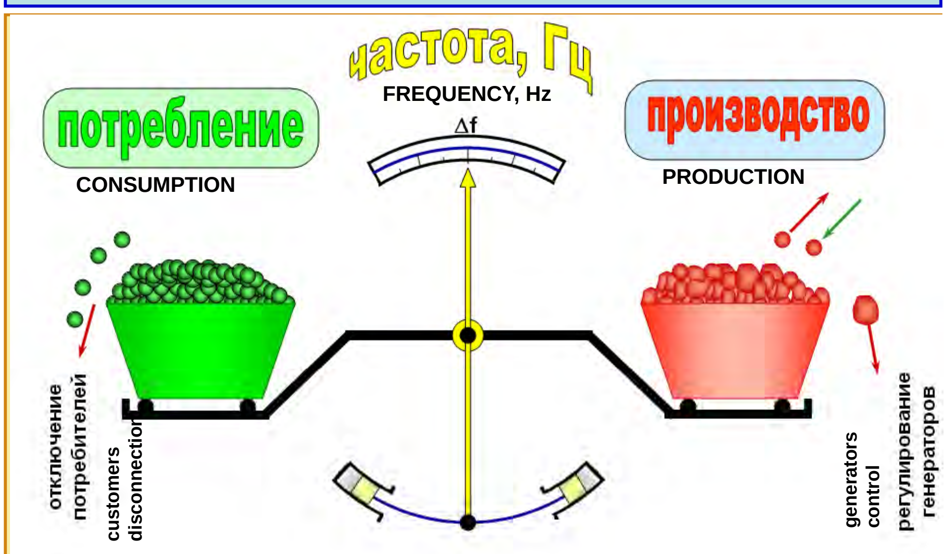

All ECA actions are aimed at providing balance of generation and consumption both in deficit and surplus parts of a power system

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SCS system is based on:

• measuring and recording pre-emergency parameters of power transmission (Preceding Condition Control – PCC);

• recording emergency disturbances and evaluating control actions (Automatic Action Adjustment - AAA);

• executing control actions (CA).

SCS CA:

• generators dropping in surplus part (GD);

• load shedding in deficit part (LS);

• network separation into asynchronously operating parts (NS);

• fast turbine valving control (FTVC);

• continuous turbine unloading in surplus part (CTU);

• quadrature compensation plants control (SR/Shunt Reactor and SC/Synchronous Condenser);

• load transfer (generator automatic start (GAS), transition of GG operating in SC mode to active mode, loading of units which have balance power, etc.).

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In the event of SCS failure and deficiency asynchronous conditions (AC) may arise in a power system.

AC are eliminated by PSP system through:

• resynchronization of out-of-step parts using FTVC in surplus part and LS in deficit part;

• breaking connections across AC by using NS;

• using combined method, i.e. breaking a part of connections across AC and resynchronizing remaining asynchronous generators.

Method for elimination of AC is primarily determined by allowable AC duration to be determined with consideration of power system’s equipment damage risk; however, it shall not exceed 30 sec.

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In CA IPS PSP mostly operates on the basis of NS.

In this respect most problematic are power centers is the deficit part of a power system where FDP system should prevent operation of power equipment with frequency:

- below 45 Hz;
- below 46 Hz during over 10 sec.;
- below 47 Hz during over 20 sec.;
- below 48.5 Hz during over 60 sec.

While lowering frequency FDP performs:

- automatic frequency load transfer (AFLT);
- automatic frequency load shedding (AFLS);
- separation of power stations or generators with balanced load in the event of inadmissible frequency drop (Frequency Separating Automatics/FSA).

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AFLT is performed through:

- start of stand-by hydro-electric generators by under frequency relay;
- transfer of hydro-electric generators operating in synchronous condenser mode to generator mode;
- loading hydro-electric and turbine generators which have standby capacity.

AFLS – special-purpose devices installed at power facilities and affecting load disconnection in the event of frequency drop down to AFLS pickup settings.

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AFLS devices can be of three types:

• AFLS-I – fast-operating (with time delay up to 0.5 sec.), with various frequency settings intended to stop frequency drop;

AFLS-II – slow operating with various frequency and time settings, intended to increase frequency after AFLS-I operation, as well as to prevent frequency hang-up at inadmissibly low level and its drop in the event of comparatively slow emergency increase in active power shortage;

limits of frequency settings – 48.8 – 48.6 Hz with level change of 0.1 Hz; initial time setting – 5-10 sec, final – 60 sec.

• AFLS special queue – designed to prevent frequency drop down to AFLS-II level highs when it is not possible to implement operational contingencies and disconnections, as well as in order to unload interconnection links in the event of power shortage;

range of frequency settings – 49.2 – 49.0 Hz.

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The following in done to increase AFLS efficiency and flexibility:

• even distribution of interruptible load among queues;

• increase in the number of queues with minimal frequency and time intervals between the queues;

• connection of customers to AFLS devices with consideration of their responsibility AFLS is adaptive, self-adjusting automatics.

Ensuring these conditions allows for implementation of a self-adjusting AFLS system which disconnects exactly as many customers whose total power corresponds to existing shortage.

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FSA – Frequency Separating Automatics is intended to separate power stations or their parts with approximately balanced load, or to separate single units for auxiliary power supply in case of emergencies with considerable power shortages.

FSA is used at thermal power stations to ensure survival of a station or individual units under conditions with abnormal power shortages when AFLS action may appear inefficient.

FSA is executed in two stages:

- with operating frequency about 46 Hz and 0.5 sec. time;
- with operating frequency about 47 Hz and 30-40 sec. time;

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Following power reserves mobilization normal configuration and conditions are restored through:

- making interconnection links via AR (Automatic Reclosing) or MR (Manual Reclosing, if there are no conditions for AR, or if AR is unsuccessful);
- further connection of customers from FAAR devices (Frequency Actuated AR) with 49.2 – 50 Hz frequency settings; initial time setting is 10-20 sec., and final time setting is determined based on possibility to eliminate power shortage.

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What types of the above mentioned automatics is it necessary to introduce in Afghanistan power system when it is included into parallel operation with CA IPS?

Who is able, given that time has been lost, to arrange ECA operation as soon as possible?

What will absence of automatics result in?

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- To determine scope and locations for installation of ECA devices a design should be urgently ordered (OJSC "Sredazenergosetproekt").
- Before construction of power grid facilities is completed the design should be introduced at CA IPS and Afghan power system power facilities (specialist installation and adjustment organizations).
- It is necessary to develop guidelines for maintaining conditions and operation of RP and ECA (CDC "Energy" and "Brishno Muassa").
- Absence of automatics will result in delay in full-scale introduction of Afghanistan power system to parallel operation with CA IPS.
- Without automatics scopes of power transmitted from CA IPS to Afghanistan will be insignificant.

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Conclusion

- Commissioning of 220 kV power transmission lines to connect Afghan power system with the Uzbek Surkhan substation is scheduled for 2009.
- Uzbek and Afghan parties implement certain activities to erect lines, re-equip substations, provide relay protection.
- However, erected lines can not be introduced into parallel operation without introducing Emergency Control Automatics devices and training personnel, including personnel for control center of Afghan power system.
- There are considerable defects and delay here. Emergency measures should be taken for the above mentioned issues not to cause delay in connecting Afghanistan power system to parallel operation with CA IPS.

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Thank you for your attention.

‘Together, rising to the challenge’

The Development and Operation of the Southern African Power Pool

Teresa Carolin
Corporate Specialist – System Operator
Eskom
South Africa

Eskom

Overview

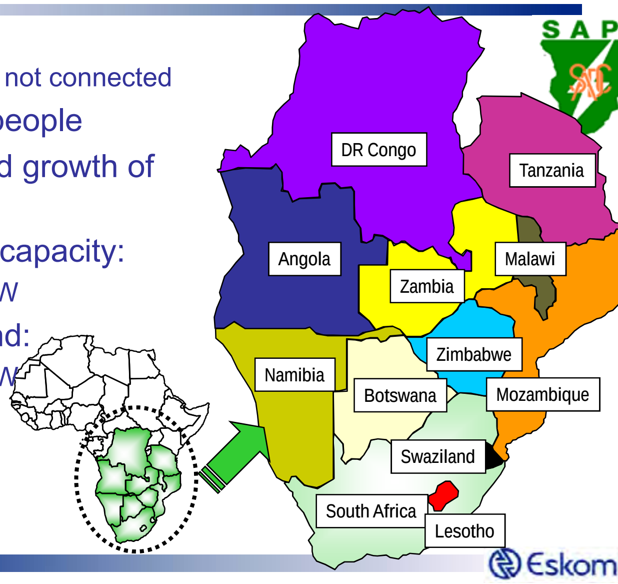
- History and overview of the SAPP
- SAPP governance and structure
- Technical characteristics of the interconnection
    - Special Protection Schemes
- Operational considerations
    - Challenges experienced
- Projects under development
- Conclusions

SAPP

Eskom

Setting the Scene

- 12 countries
  - 3 countries not connected
- 230 million people
- Average load growth of about 3%
- Operational capacity:
  - ~47 000 MW
- Peak demand:
  - ~44 000 MW

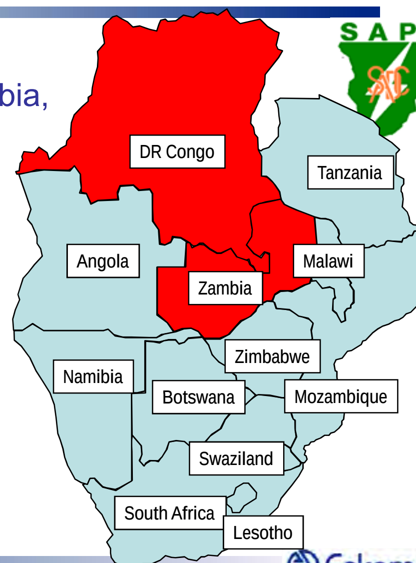


S A P P

Eskom

Development of the Interconnected System

- In the 1950’s, lines connected DRC and Zambia, thus introducing interconnection and facilitating early regional trade.

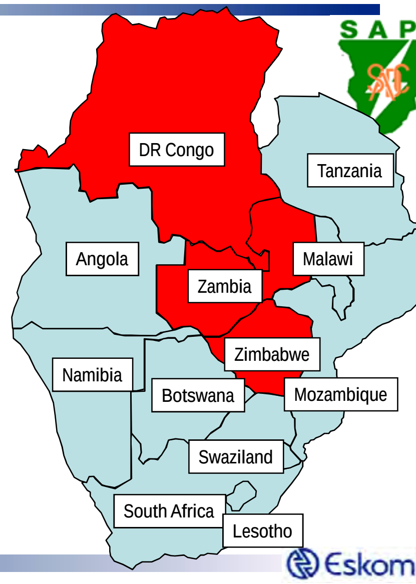


S A P P

Eskom

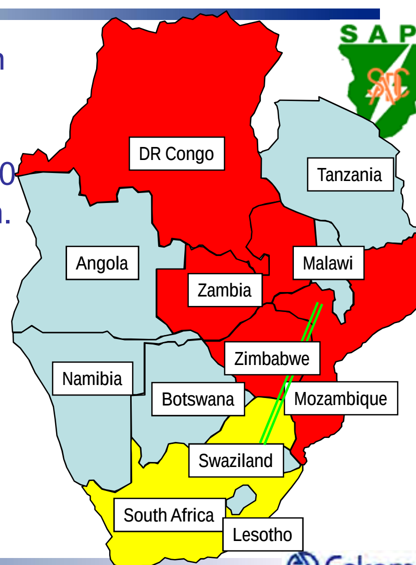
Development of the Interconnected System

- In the 1950's, lines connected DRC and Zambia, thus introducing interconnection and facilitating early regional trade.
- Following the construction of the Kariba dam in the 1960's, connection started of the Zambian and Zimbabwean systems.



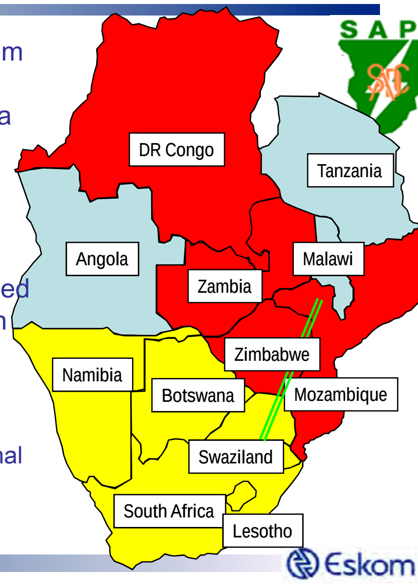
Development of the Interconnected System

- In 1975, the South African system connected to Northern Mozambique (Cahora Bassa) via a 1400 km HVDC interconnection.



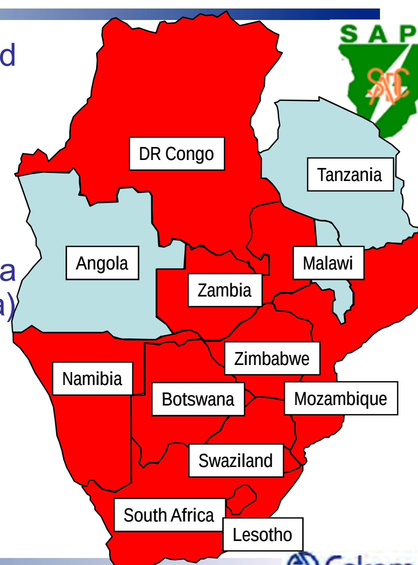
Development of the Interconnected System

- In 1975, the South African system connected to Northern Mozambique (Cahora Bassa) via two 1400 km HVDC lines.
- The Namibian, Southern Mozambique, Botswana, Swaziland and Lesotho developed connections to the South African networks and eventually two distinct networks existed:
  - Northern network: mainly hydro
  - Southern network: mainly thermal



Development of the Interconnected System

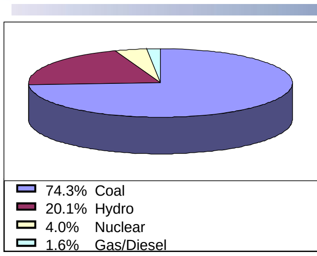
- Relatively weak 220 kV and 132 kV interconnections existed between the two systems.
- In 1995, a 400 kV line was connected between Zimbabwe and South Africa (later turned into Botswana) which connected the two systems.
- This provided a path for regional trade and cooperation between utilities.



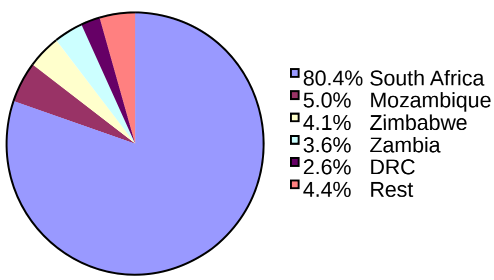
Development of the SAPP

- Each utility provided representatives to coordinate both the technical aspects of the interconnection, as well as the administrative and governance issues.
- The purpose behind the interconnection was initially that of a "co-operative pool" with the associated benefits of enhanced reliability and reduced capital spending of each utility.
- Countries were further able to optimise the available resources and rely on each other in emergencies.
- Each utility was afforded equal opportunity to participate in the development of the pool and documentation which would govern the operation of the pool.

Generation Mix and Country Contribution



- South Africa's abundant coal resources dominate the generation mix in Southern Africa
- There is considerable possibility for future development of the hydro resources in the region



SADC

- The Southern African Development Community (SADC) is an inter-governmental organization headquartered in Gaborone, Botswana. Its goal is to further socio-economic cooperation and integration as well as political and security cooperation among 15 southern African states. It complements the role of the African Union.
- The SADC vision is one of a common future, a future within a regional community that will ensure economic well-being, improvement of the standards of living and quality of life, freedom and social justice and peace and security for the peoples of Southern Africa. This shared vision is anchored on the common values and principles and the historical and cultural affinities that exist between the peoples of Southern Africa
- The (SADC) Government Ministers and Officials are responsible for policy matters, which are normally under their control in terms of the national administrative and legislative mechanisms that regulate the relations between the governments of the Member States and their respective Electricity Supply Enterprises.
- The Executive Committee shall refer major policy issues that may arise in SAPP to SADC through the SADC reporting protocol.
- The interactions between SADC and SAPP shall be in accordance with the SADC reporting structure.

SAPP Reporting Protocol

Council

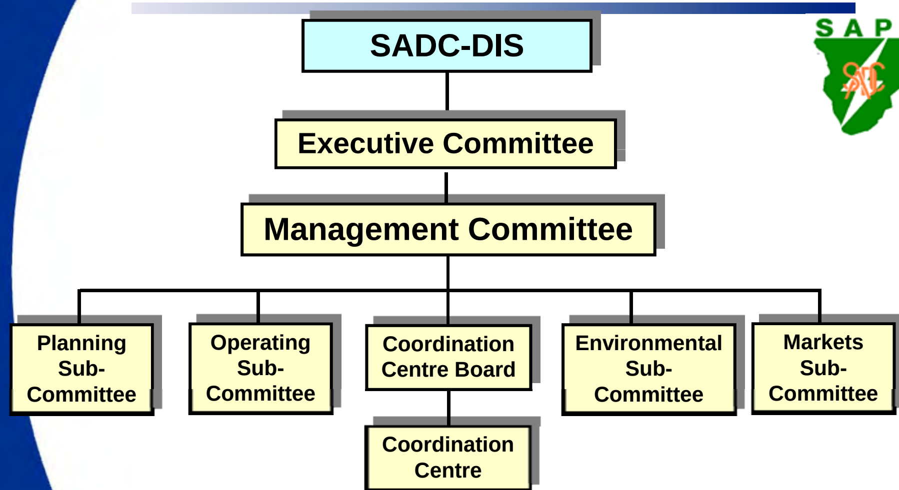
Integrated Council of Ministers

Committee of Senior Government Officers

SADC Directorate of Infrastructure and Services

SAPP

Management and Government Structure



- The chairman of each committee is elected, and holds office for at least one year, but maximum of two years

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Governance structures

- The Chief Executives of each utility sits on the Executive Committee
- The EC is the Governing Authority of SAPP and performs the following functions:
  - formulation of the objectives of SAPP
  - approve committees, task forces and work groups
  - approve the Coordination Center budget
  - decides on the SAPP membership
  - approve any changes to SAPP governance
- Oversee work and decide on recommendations of the Sub-Committees and Coordination Center Board

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Planning Sub-Committee

- Two members from each utility are represented on this committee. The functions of the committee include:
  - Establishing and updating common planning and reliability standards
  - Reviewing an overall integrated generation and transmission plan
    - The plan is purely indicative and does not create an obligation
  - Evaluation of software and other tools which will enhance the value of planning activities
  - Specifying the reliability standards that shall be used to determine the Accredited Capacity Obligation of each Operating Member.
  - Specifying compliance criteria, which will enable each Operating Member to comply with its Accredited Capacity Obligation.
  - Assessing the benefits attributable to each Operating Member resulting from the installation of protection relays, control equipment or any system study,

Operational Sub-Committee

- Two members from each utility are represented on this committee. The functions of the committee include:
  - Conducting system operational studies.
  - Establishing and updating the methods and standards used to measure the technical performance of generating units and transmission facilities.
  - Establishing and updating the formula for determining the operating reserve obligations of the Operating Members and ensuring that these obligations are met.
  - Monitoring each Member’s compliance to the declared system peak and accredited capacity obligations.
  - Updating approved operating procedures for the SAPP interconnected power
  - system.
  - Monitoring system performance against set criteria.
  - Ensuring that generation and transmission maintenance schedules of Operating Members are co-ordinated.
  - Ensuring that each Operating Member is equipped with or contracts the necessary control gear and ancillary facilities for reliable operation of the SAPP interconnected system.

Environmental Sub-Committee

- Two members from each utility are represented on this committee. The functions of the committee include:
  - Develop Environmental Guidelines for SAPP and review and evaluate such guidelines from time to time.
  - Liase with environmental organisations of Governments of Member States
  - through the appointed representative.
  - Keep abreast of world and regional matters relating to air quality, water quality,
  - land use and other environmental issues.
  - Make recommendations to harmonize regional environmental legislation relating
  - to electrical energy in the whole production chain.
  - Provide Key Performance Indicators for environmental impact assessment for SAPP interconnector projects.
  - Determine the environmental risk in SAPP that would affect the sustainability of SAPP.

Market Sub-Committee

- This committee is a newly established committee, aiming to establish the appropriate structures and mechanisms to enable a competitive pool
- The duties of the committee include:
  - The continued development of an appropriate electricity market for the SADC Region.
  - The design and recommendation of a suitable market structure for SAPP.
  - Determination of criteria to authorize Members to trade.
  - The responsibility to admit and authorise Members to trade, risk management, research and benchmarking.

SAPP Coordination Center

- The coordination center (CC) was established in Harare, Zimbabwe in 2000. It is not a control center
- Functions of the CC include:
  - Monitoring transactions, control performance criteria and adherence to Accredited Capacity Obligations
  - Convening investigations following disturbances affecting the parallel operation of the pool.
  - Evaluate the impact of future projects on the operation of the pool and advise the Operating Sub-Committee accordingly.
  - Perform studies to determine transfer limits on tie lines and monitor adherence to these limits.
    Establish and update a database containing historical and other data to be used in Planning and System Operation studies
  - Monitor the availability of the communication links between the utility Control Centers and between these Control Centers and the Co-ordination Center.

Governing Legal Documents

- Inter-Governmental Memorandum of Understanding (IGMOU)
  - Established SAPP
  - Signed by SADC member countries in August 1995
  - Revised document signed in February 2006
- Inter-Utility Memorandum of Understanding (IUMOU)
  - Established the management of SAPP
  - Signed by Utilities in December 1995
  - Revised document signed in April 2007
- Agreement Between Operating Members
  - Signed by Operating Members only
  - Revised document signed in April 2008
- Operating Guidelines
  - First developed in 1996
  - Currently under review

Changes to Documents

- A number of changes have occurred since the development of SAPP and it was necessary to revise the documents in light of these changes
- Changes have included:
  - SADC Institutions have undergone a process of restructuring under the 2001 Agreement Amending the Treaty of SADC.
  - The energy sector has progressed since the inception of SAPP and various national power utilities are in the process of undertaking reforms in their electricity sector
  - many of the utilities had undertaken a process of internal restructuring and may also be subject to national restructuring of the electricity supply industry within the country

SAPP membership

- Electricity Supply Enterprise is an entity which
  - operates a control centre around the clock;
  - which owns or controls through other means the operation of several generating units and regularly operates such units to meet a portion or all of its load obligations;
  - which owns a transmission system already interconnected internationally or which may be interconnected in future with neighbouring Electricity Supply Enterprise(s)
- An Electricity Supply Enterprise is either a:
  - Power Utility
  - Independent Power Producer
  - Independent Transmission Company
  - Service Provider

Technical characteristics of the interconnection

- The area that network covers is extensive, with many relatively weak interconnections.
- It is a predominantly a.c. network, with two d.c. connections.
- Eskom is a predominant component of the entire interconnection.
- Besides the specific Special Protection Schemes that will be discussed, a number of other issues are worth mentioning
  - When SAPP was established, a comprehensive small signal stability study was performed identifying a number of modes of inter-area oscillation
  - The parallel operation of the 400 kV a.c. connection between Zimbabwe and South Africa, with the HVDC line between Mozambique and South Africa, required a sophisticated control system to manage
  - Under frequency load shedding is coordinated with the tripping of interconnectors at specific frequencies

Small Signal Instability

- Following the connection of the two systems with the 400 kV interconnection, significant system oscillations were noted, specifically between the Zimbabwean and South Africa systems.
- The studies identified a number of other oscillations and measures were introduced to damp these oscillations.
- Primarily, use was made of PSSs and the Power Oscillation Damping function of the SVC's, but additional damping was provided by the control system commissioned to manage the parallel operation of the a.c. and d.c. networks.
- For many years small signal instability has not been a problem, but in recent time, the problem has resurfaced.
- This is believed to be as a result of reduction of number of PSSs on the system (due to generators not being in service) as well as other changes in the system impedance.

Special Protection Schemes

- A number of special protection schemes are installed at various locations on the interconnection.
- The ones discussed below directly influence the interconnections with the Eskom network.
- Not all schemes are SAPP requirements, but each influences a neighbouring utility.
- Each scheme is designed to isolate a specific problem, prior to it becoming a major incident.

SAPP

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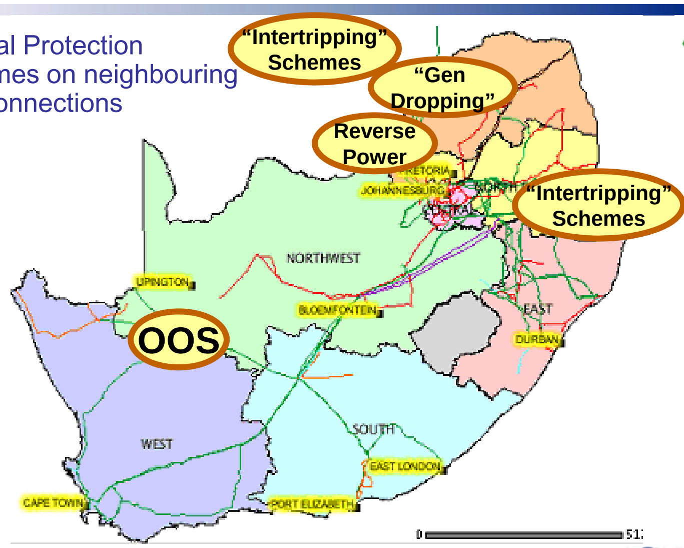
Schematic of Eskom Network

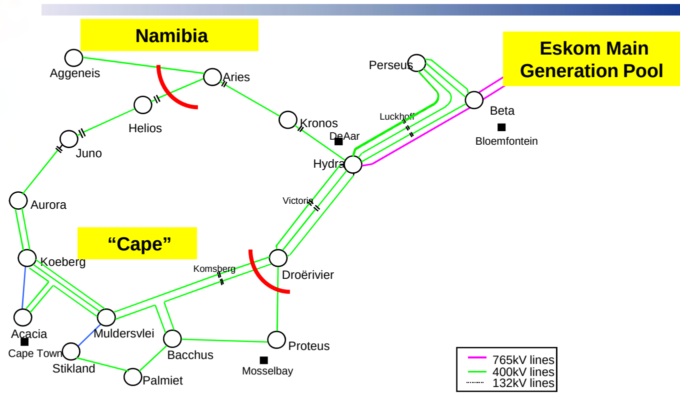
- Special Protection Schemes on neighbouring interconnections



SAPP

Eskom

Out Of Step Protection



- Loss of specific lines, results in the loss of synchronism between the main generation pool in the North East of the country, and that in the "Cape" area
- The OOS protection operates and islands the local load onto the available generation, with the Namibian network remaining connected to the larger part of the interconnected power system
- UFLS trims the load to match the available generation

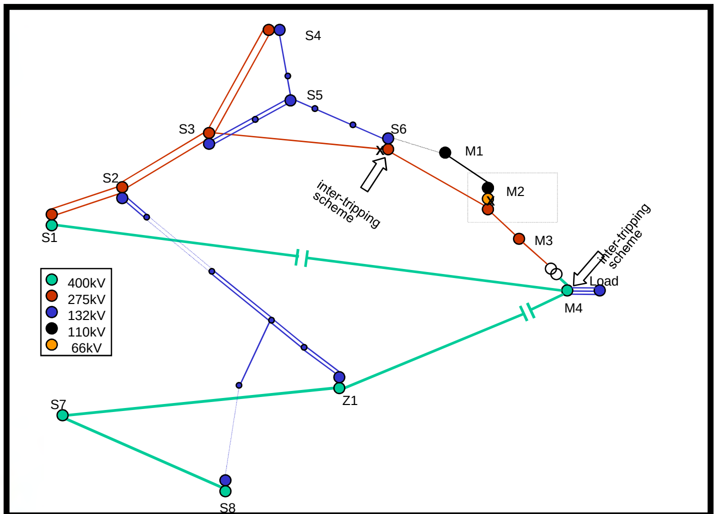
Eskom

"Intertripping" schemes

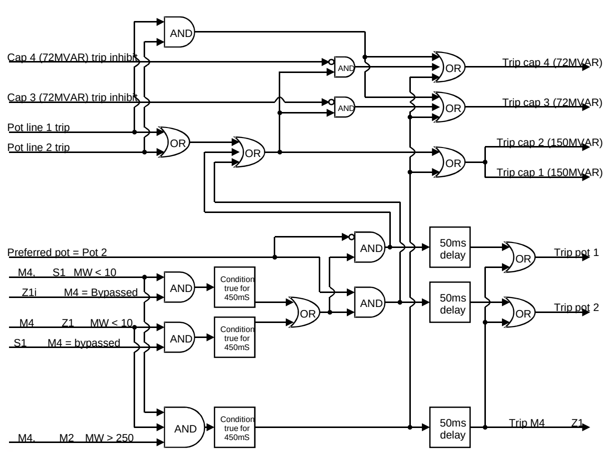
- The interconnection between Eskom and the Southern Mozambique network used to consist of a relatively weak 275 kV and 132 kV interconnection.
- Loss of a specific line would result in voltage collapse not only in the Mozambique network, but also parts of Eskom's network
- The intertripping scheme considers the status of a specific line as well as measuring the amount of MW flowing on the remaining line
- If it exceeds a certain threshhold, the line trips
- This network was strengthened with a 400 kV overlay, when required to supply a large bulk load in Mozambique.
- While the network is designed to accommodate a single contingency, anything beyond this requires load to be shed.
- The scheme considers the status of the 400 kV lines, confirmed by the MW flowing on the lines, and if necessary trips a portion of the load together with the associated shunt compensation.

Eskom

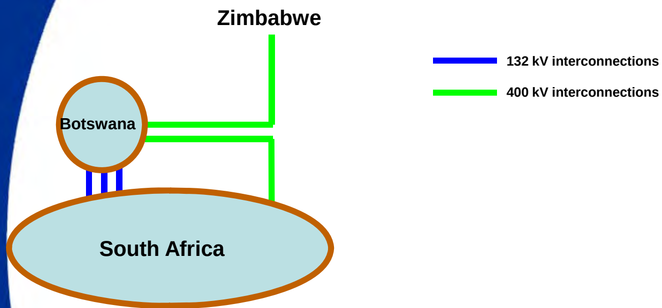
Network Schematic



"Intertripping" schemes

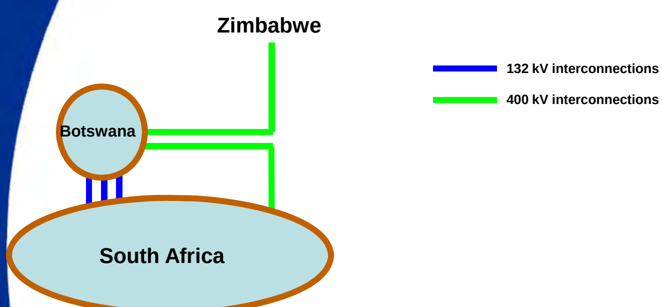


"Intertripping Scheme"



- The parallel operation of the 400 kV interconnection between Zimbabwe, via Botswana, with South Africa and the underlying lower voltage networks, results in the possibility of overloading and voltage collapse, specifically in the Botswana network should one link of the 400 kV interconnection trip
- Thus if one interconnection trips, the remaining will also trip
- This philosophy is being relooked at considering the current magnitude and direction of power flow on the interconnection

Reverse Power tripping



- Similar to the previous discussion, too much power flowing through the Botswana network, either as a result of the loss of the 400 kV line or loss of equipment on the South African system, will result in the collapse of the Botswana network
- Reverse power relays, detecting power flowing greater than a specific magnitude, will result in severing of this 132 kV interconnection between Botswana and South Africa

“Gen Dropping” scheme

- The location of the interconnection of the northern system to the South African system, is at a location where there is traditionally a challenge with power evacuation.
- The power station situated here is far from local load and with lines out of service, it was necessary to reduce the generation at the power system
- Imports into South Africa, worsened this situation as additional power had to be evacuated
- A “generator dropping” scheme, considering predefined “Power Jump” and “Acceleration Energy” values, was designed to trip generators should a close up fault potentially result in instability
- Additionally, breakers with faster clearing times were installed to minimise the possibility of this occurring.
- This scheme is being relooked at with the integration of additional power stations in the area

Transactions between utilities

- A number of different agreements exist between the various SAPP members.
  - Many are bilateral agreements, of varying duration.
  - On a daily basis, additional requests for available energy or wheeling paths are made and where possible are accommodated.
- Up until recently, any additional power available was transacted on a Short Term Energy Market (STEM).
- As the SAPP moves from a co-operative pool to a competitive pool, one of the first trading mechanisms will be a Day Ahead Market (DAM)
  - This is currently being operated on a trial basis
- There is currently no Balancing Market in SAPP

Operational Communication

- Outage information
  - Each utility is responsible to notify affected utilities and the coordination center of equipment outages that affect the ability to supply or wheel energy at least two weeks in advance.
  - Where possible, neighbouring constraints are accommodated.
  - For every interconnection, a Maintenance and Operating Committee (MOC) is established and annual meetings are held to deal with specific operational issues.
- Transfer limits between utilities
  - In conjunction with utilities, the coordination center performs studies that determine the transfer limits between the utilities.
  - Challenges arise around this due to lack of understanding around internal system constraints and coordination of system databases.

Interaction between utilities

- A number of meetings and interactions are held between the various utilities
- Bi-annual sub-committee and committee meetings are held, with the venue rotating between all members
- Additional meetings held as required
  - Operational discipline
  - Finalisation of “Inadvertent Energy” data
  - Specific disturbance investigation
  - Combined studies

Technical Challenges

- Lack of infrastructure development (Transmission and Generation) corresponding to the increased load growth over the last few years.
- Maintaining updated study case files (in common software format).
- Due to a number of reasons, some utilities are running at reduced load and reduced generation. The associated lack of dynamic control is having a negative impact on their system stability.
- Increasing internal constraints resulting in reduced availability of transmission paths for inter utility transactions.
- Difficult to balance the requirements (and funding)between utility strengthening and network strengthening to increase transaction opportunities.

Other Challenges

- Time frame to get changes implemented.
- Introduction of IPPs
  - Lack of formal balancing mechanism.
  - Funding.
- Moving from environment of “surplus capacity” to one of “capacity deficit” .
  - Same time trying to introduce a Day Ahead Market.
  - Low volume of trade.
- Lack of operational discipline, and no easy mechanism to actually force compliance.

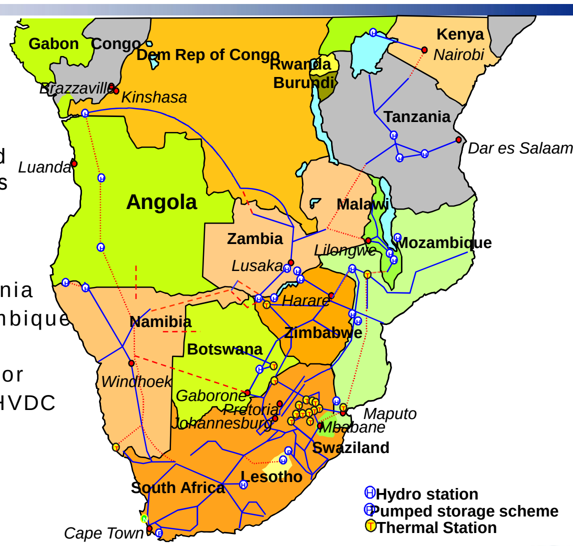
Projects under development

- New Transmission interconnections:
  - Westcor
  - Zizabona
  - Zambia – Tanzania
  - Malawi - Mozambique
- Strengthening of:
  - DRC – Zambia
  - Central Corridor
  - Mozambique HVDC
- A number of IPPs are being explored in the region

Transmission Projects under development

Over USD 4.7 billion Would be required to develop the identified transmission projects

- Westcor
- ZIZABONA
- Zambia-Tanzania
- Malawi-Mozambique
- DRC-Zambia
- Central Corridor
- Mozambique HVDC Strengthening



Conclusions

- The SAPP vision is to:
  - Facilitate the development of a competitive electricity market in the Southern African region
  - Give the end user a choice of electricity supply
  - Ensure that the Southern African region is the region of choice for investment by energy intensive users
  - Ensure sustainable energy developments through sound economic, environmental and social practices
- To this end SAPP is
  - Changing from a co-operative pool to a competitive power market.
  - Reviewing membership to allow for more players.
  - Expanding both transmission & telecommunication links between members.
  - Expanding generation capacity and attract high intensive energy users.
  - Enhancing Human Capacity development and expansion

Key learnings

- In the real time environment, issues associated with operational discipline and empowerment of operators are key.
- A central coordinating function provides a neutral view that can take care of many of the administrative functions.
- Absolute transparency is required in technical issues (such as disturbance investigations).
- Continued focus is required on the technical aspects of the interconnection as the combined effect of small changes over time can be significant.
- Because meetings are held twice a year, many issues take a long time to resolve and it is therefore important to address issues as they arise.
- All members have a role to play, and the relative size of a utility should not dominate the decisions taken.
- There are definitely benefits to operate in an interconnected manner, but the management of the technical and financial issues must continually be focused on.

BONNEVILLE
POWER ADMINISTRATION

February 4, 2009

Introduction

The United States Department of Energy

Bonneville Power Administration (BPA)

- Tom Roseburg, System Protection Engineer
- Dan Weston, RAS Design Engineer

What is BPA?

Bonneville Power Administration

BPA serves the U. S. Pacific Northwest through operating an extensive electricity transmission system and marketing wholesale electrical power at cost from federal dams, one non-federal nuclear plant and other nonfederal hydroelectric and wind energy generation facilities. BPA aims to be a national leader in providing high reliability, low rates consistent with sound business principles, responsible environmental stewardship and accountability to the region.

Overview

Bonneville Power Administration

- BPA Transmission System
- Columbia River Treaty
- Northwest Power Pool

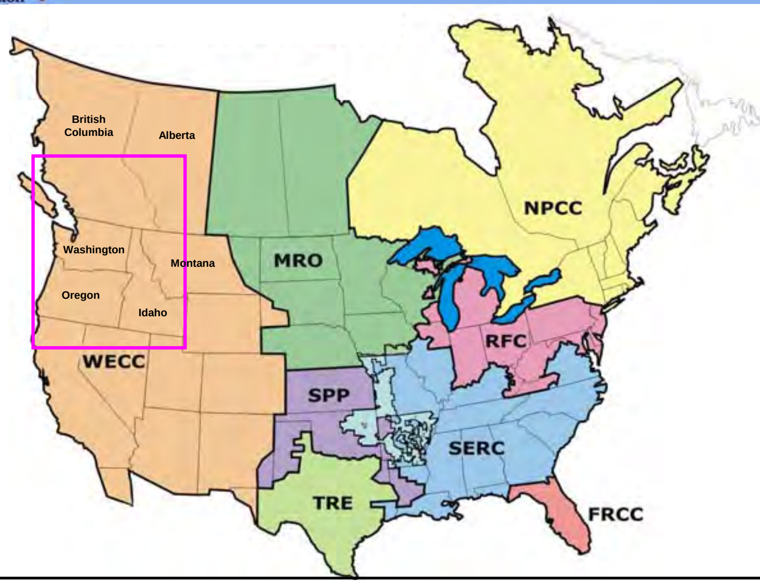
BPA Transmission System

Bonneville Power Administration

- Geographic area – Where is BPA?
- History
- Statistics
- Generation Resources
- Load Centers
- Interties
- Unique features
- Control Centers

North American Electrical System Regions

Bonneville Power Administration



BPA Area

Bonneville Power Administration

Federal Columbia River Power System

- Washington
- Oregon
- Idaho
- Western Montana
- S. British Columbia

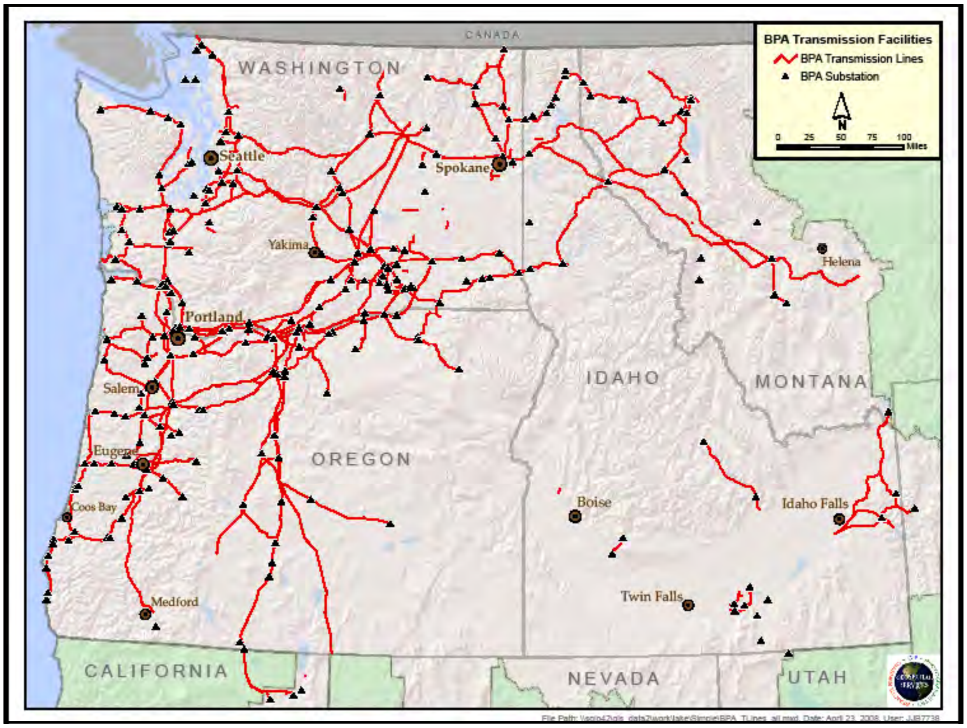
Bonneville Dam

Bonneville
Power Administration

BPA History

Bonneville
Power Administration

- Columbia River development – 1930’s
- Bonneville Dam – first federal dam
- BPA established originally to market the power from Bonneville Dam (1937)
- Scope includes all facilities constructed by the US Federal Government on the Columbia River and its tributaries.



BPA Statistics

Bonneville
Power Administration

- 300,000 Square miles (480,000 square km)
- Population: 12 million
- Transmission System: 15,000 circuit miles (24,000 circuit km) 115 kV to 500 kV AC, 1000 kV DC (264 mi/422 km)
- Generating facilities: 31 federal dams = 20,460 MW nameplate capacity (power sales only)
- Peak load: 18,000 MW (BPA only)

BPA Generation Resources

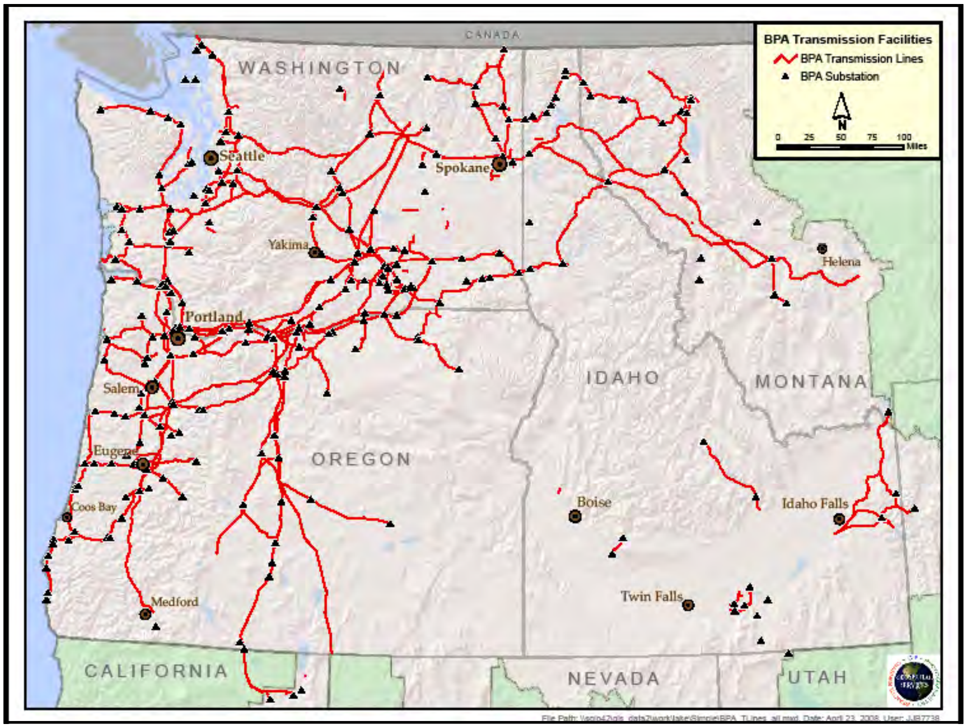
Bonneville Power Administration

- BPA does not own or operate any generation resources (USCE, USBR)
- Hydroelectric power: 20,460 MW
- Nuclear power: 1,150 MW
- Wind power: 1,600 MW
- Other: 300 MW
- Concentrated in Central Washington and North-Central Oregon

Load Centers

Bonneville Power Administration

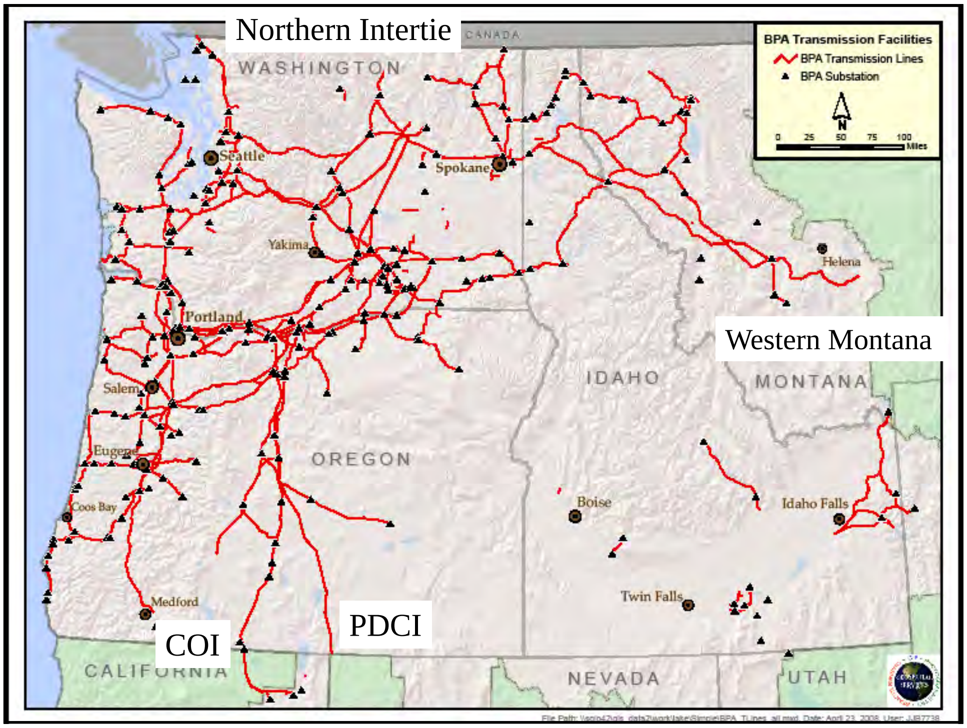
- Seattle, Washington
- Portland, Oregon
- Spokane, Washington
- Tri-cities area (Kennewick, Pasco, Richland, Washington)



Interties to Other Regions

Bonneville Power Administration

- California-Oregon AC Intertie (COI)
- Pacific DC Intertie (PDCI)
- Northern Intertie – British Columbia
- Western Montana



BPA System Unique Features

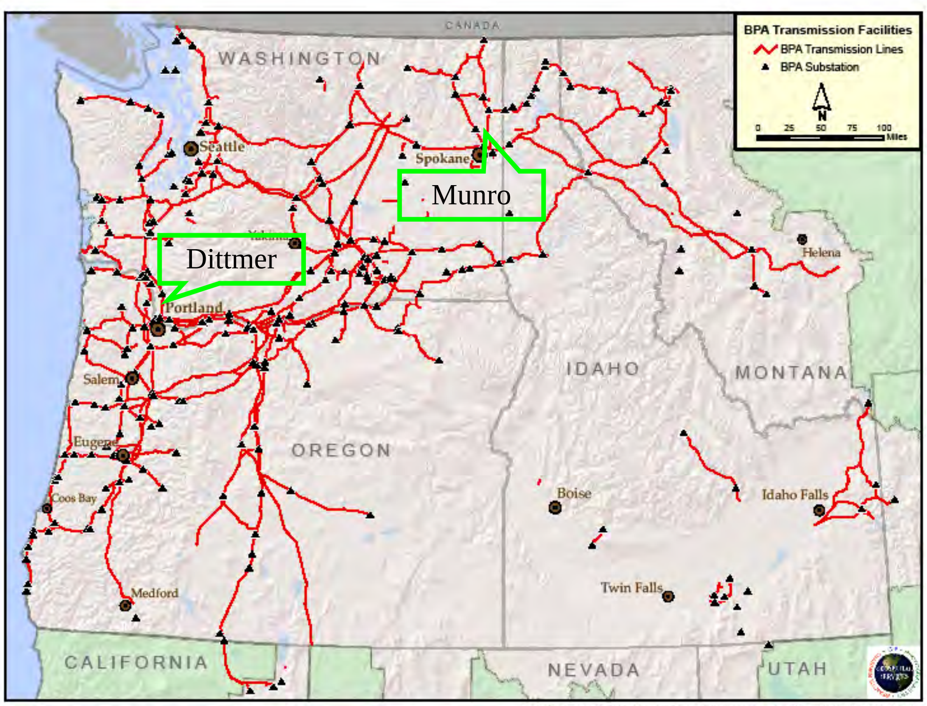
Bonneville Power Administration

- BPA does not own or operate generating facilities
- BPA does market power from many generating facilities
- BPA does not distribute to individual consumers – only wholesale power

BPA Control Centers

Bonneville Power Administration

- Dispatch and control of BPA Transmission System (Transmission Business Line)
- Dittmer Control Center, Vancouver, Washington
- Munro Control Center, Spokane, Washington
- Each control center can operate the entire system.
- Normally Dittmer dispatches and controls the main grid (above 230 kV)
- Normally Munro dispatches and controls the lower voltage facilities (230 kV and below)



BPA Power Business Line

Bonneville Power Administration

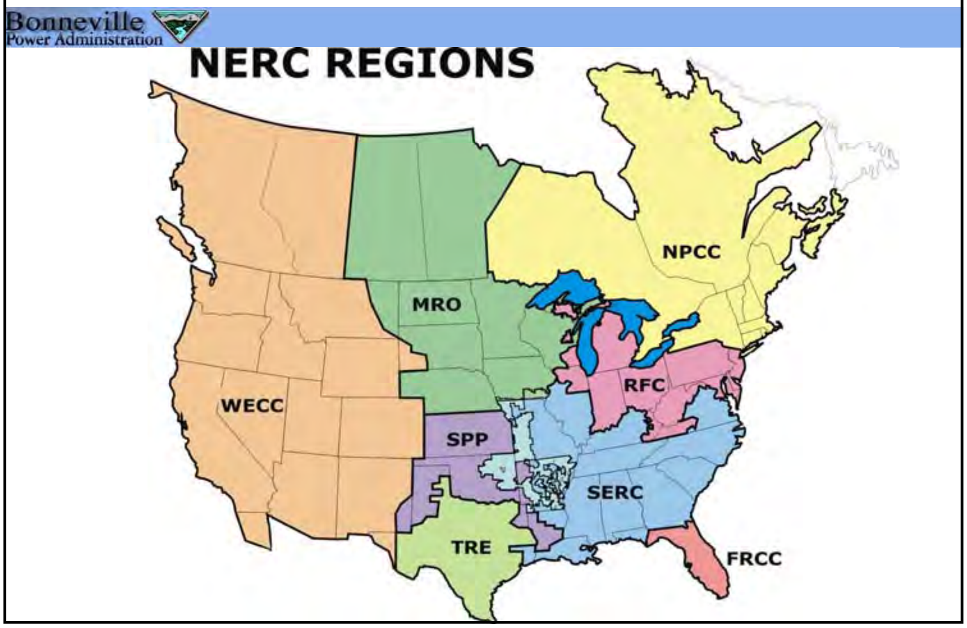
- Coordinate sales of power generated at Columbia River power plants

Transmission Regulating Organizations

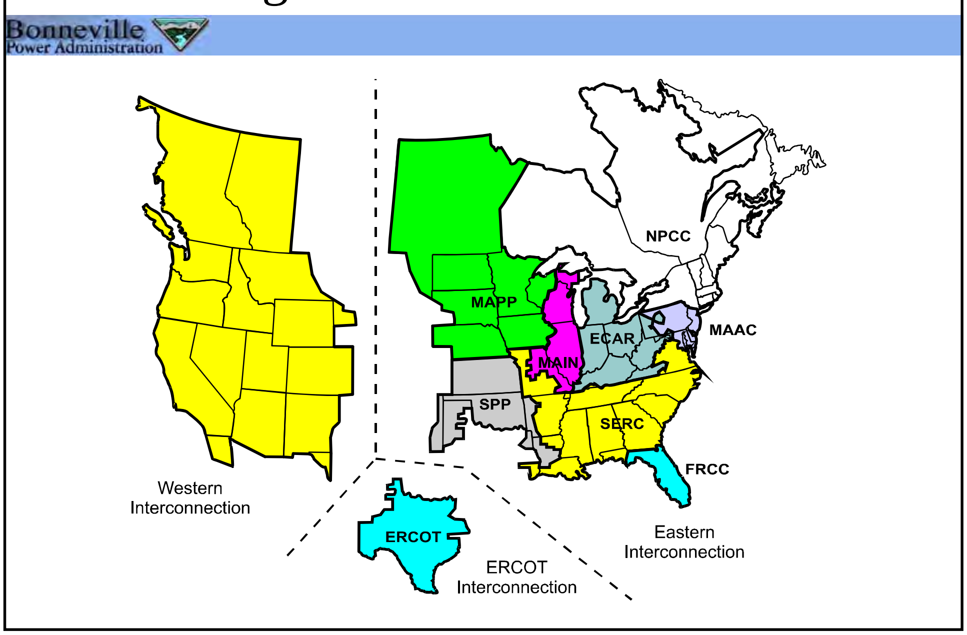
Bonneville Power Administration

- Reliability: Standards and Organizations
  - North American Electric Reliability Corporation (NERC)
  - Federal Energy Regulatory Commission (FERC)
  - Western Electricity Coordinating Committee (WECC)
- Treaties
  - Columbia River Treaty
- Coordinating organization
  - Northwest Power Pool (NWPP)

US Electrical System Regions



Regional Interconnections



NERC

Bonneville Power Administration

- ***North American Electric Reliability Corporation***
- *"NERC's mission is to improve the reliability and security of the bulk power system in the United States, Canada and part of Mexico. The organization aims to do that not only by enforcing compliance with mandatory Reliability Standards, but also by acting as a "force for good" -- a catalyst for positive change whose role includes shedding light on system weaknesses, helping industry participants operate and plan to the highest possible level, and communicating Examples of Excellence throughout the industry.* " NERC Website
- NERC Job: "NERC develops and enforces Reliability Standards; monitors the bulk power system; assesses adequacy annually via a 10-year forecast and winter and summer forecasts; audits owners, operators, and users for preparedness; and educates and trains industry personnel. "

FERC

Bonneville Power Administration

- FERC is responsible for:
  - Regulating the interstate transmission of natural gas, oil, and electricity within the U. S.
  - Regulating the wholesale sale of electricity (individual states regulate retail sales).
  - Licensing and inspecting hydroelectric projects.
  - Approving the construction of interstate natural gas pipelines, storage facilities, and Liquefied Natural Gas (LNG) terminals.
  - Monitoring and Investigating Energy Markets.

WECC

Bonneville Power Administration

- The Western Electricity Coordinating Council (WECC) interconnection-wide focus is intended to complement current efforts to form Regional Transmission Organizations (RTO) in various parts of the West.
- WECC continues to be responsible for coordinating and promoting electric system reliability. In addition to promoting a reliable electric power system in the Western Interconnection, WECC will support efficient competitive power markets, assure open and non-discriminatory transmission access among members, provide a forum for resolving transmission access disputes, and provide an environment for coordinating the operating and planning activities of its members as set forth in the WECC Bylaws.

WECC

Bonneville Power Administration

- The WECC region encompasses a vast area of nearly 1.8 million square miles. It is the largest and most diverse of the eight regional councils of the North American Electric Reliability Council (NERC). WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 western states in between. Transmission lines span long distances connecting the verdant Pacific Northwest with its abundant hydroelectric resources to the arid Southwest with its large coal-fired and nuclear resources. WECC and the nine other regional reliability councils were formed due to national concern regarding the reliability of the interconnected bulk power systems, the ability to operate these systems without widespread failures in electric service, and the need to foster the preservation of reliability through a formal organization.
- Due to the vastness and diverse characteristics of the region, WECC's members face unique challenges in coordinating the day-to-day interconnected system operation and the long-range planning needed to provide reliable and affordable electric service to more than 71 million people in WECC's service territory.

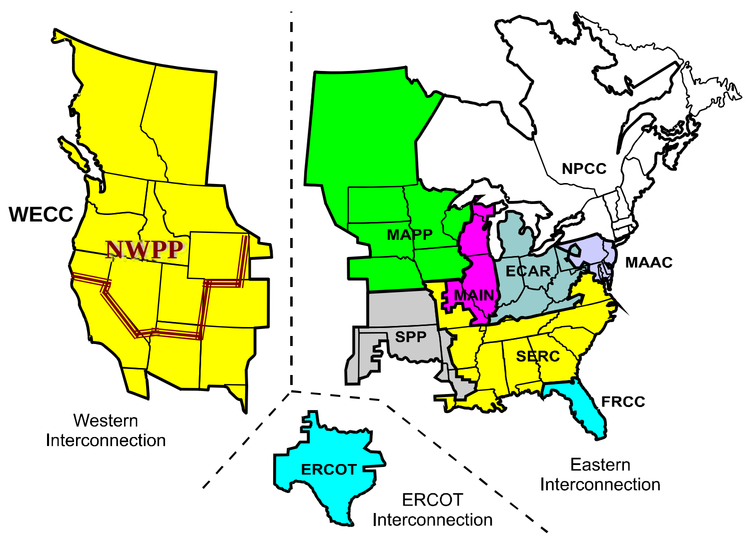
WECC Reliability Coordinators

Bonneville Power Administration

- Offices in Vancouver, Washington and Denver, Colorado
- Monitor electric bulk power system for compliance with reliability standards; direct utilities to make adjustments when necessary

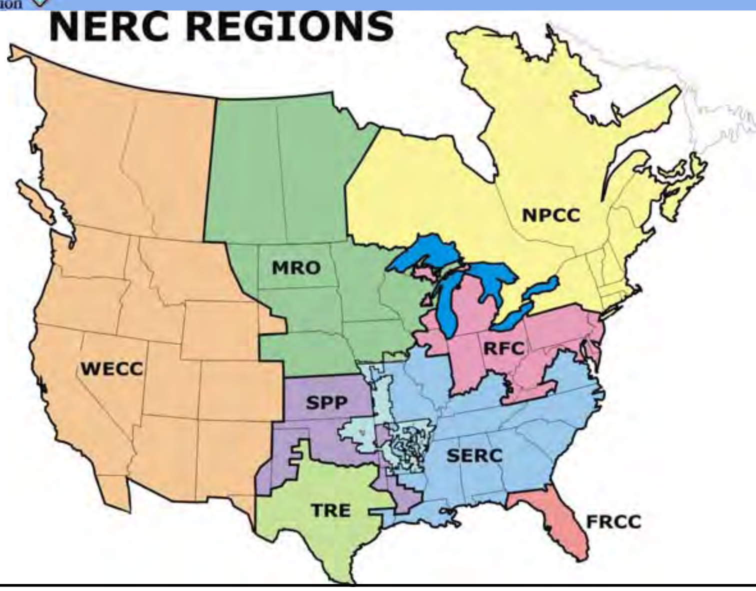
Northwest Power Pool (NWPP)

Bonneville Power Administration



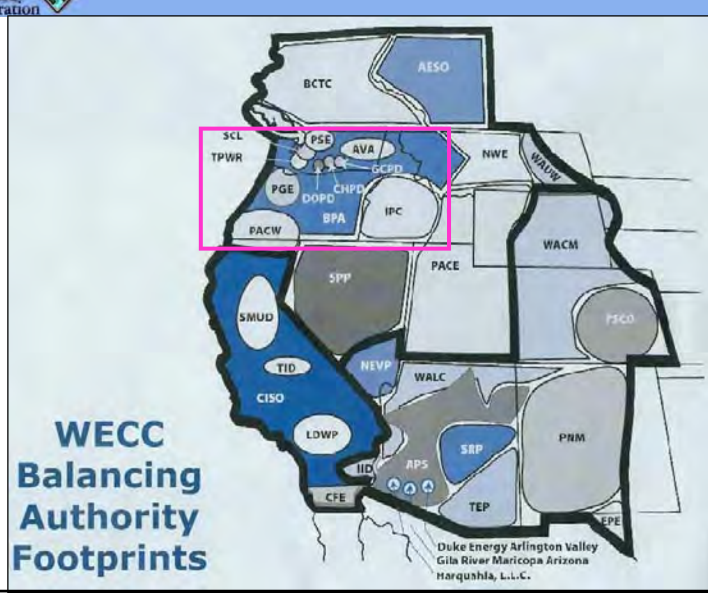
BPA Overview

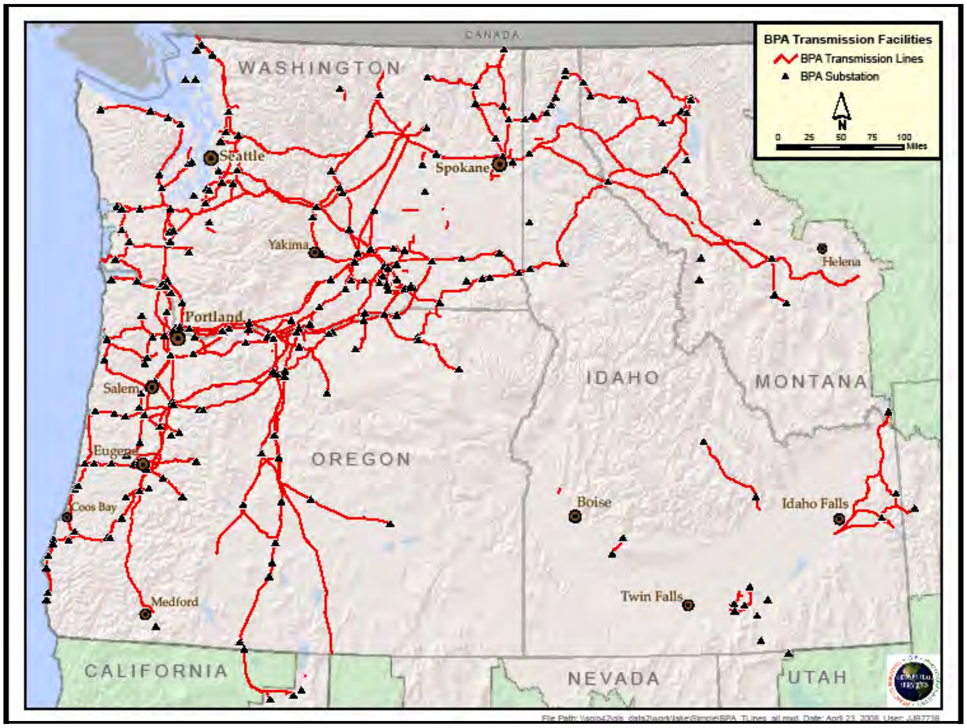
Bonneville Power Administration



BPA Overview

Bonneville Power Administration





BPA Transmission System

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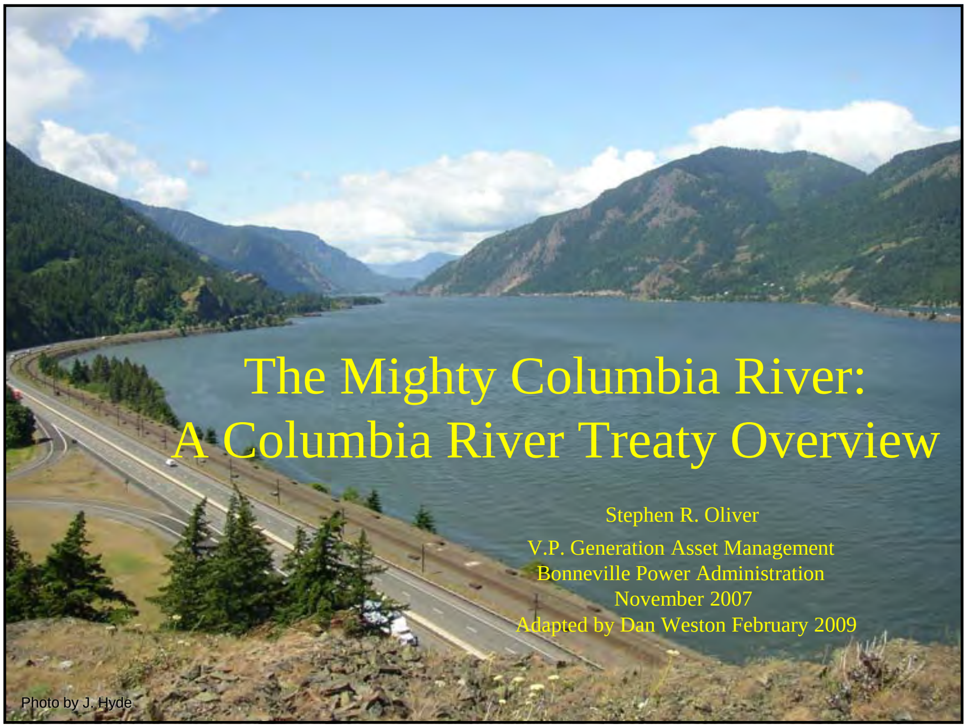
- 15,000 miles of transmission lines.
- Mostly 500 kV, 230 kV and 115 kV.
- Interconnect with many other power providers in the Pacific Northwest.



Columbia River Gorge

Bonneville Power Administration

Columbia River

Bonneville
Power Administration

- **The Columbia River is the fourth largest river in North America as measured by average annual flow of 198 million acre feet (MAF) (244 cubic kilometers (km^3)) at its mouth and about 134 MAF (165 km^3) at The Dalles, Oregon, where it cuts through the Cascade Mountains.**
- **The Columbia is the most "powerful" river in North America, as measured by flow times change in elevation.**

Columbia River Treaty Overview

Bonneville Power Administration

- The implementation of the Columbia River Treaty in 1964 was arguably the most significant and farthest reaching decision in US Pacific Northwest electric power history since the decision to dam the Columbia River.
- The Treaty coordination between Canada and US on power and flood control provides $100's of millions of dollars of annual mutual benefits across the Columbia River Basin.

Columbia River Treaty Overview

Bonneville Power Administration

- The Treaty motivated infrastructure and governance development such as the electrical intertie to California, regional power preference legislation, added generators at most Columbia dams, and several vital regional power coordination agreements.
- The Treaty's 60th anniversary is Sep. 2024 and the potential exists for either party to terminate after that date.

In the Beginning - - -

Bonneville Power Administration

- Prior to 1909, U.S.-Canada water issues were resolved on a case-by-case basis
- The 1909 Boundary Waters Treaty set out rules for dispute resolution between the U.S. and Canada, and created the International Joint Commission (IJC) to resolve issues – signed by the U.S. and Great Britain

In the Beginning - - -

Bonneville Power Administration

- Western U. S. watersheds were relatively ignored until the 1930's, when development on the Columbia main stem began.
- Toward the end of WWII the federal governments directed the IJC to start looking at development of the Columbia Basin for power and flood control, but relatively little in the way of studies was actually done, until:

In the Beginning - - -

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Power Administration

- **Memorial Day flood of 1948, with over 50 deaths and destruction of Oregon's 2nd largest city and >$100 million damages in Canada and U.S., triggered new studies focused on flood control, and power.**


FLOOD CRUMBLES VANPORT, HEAVY DEATH TOLL FEARED

The Oregonian

Lake Dike Gives Way, 18,500 Made Homeless, Scores Reported Hurt

Why Did We Need a Treaty?

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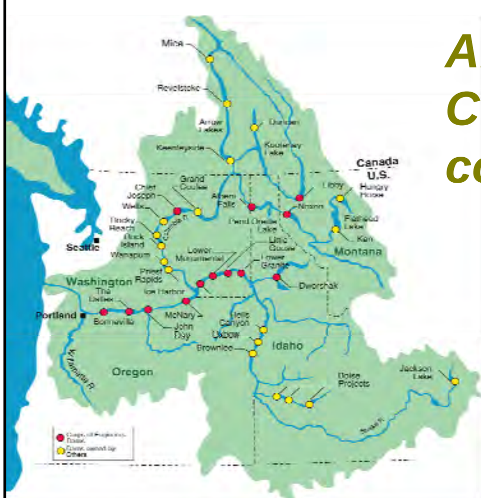


About 1/3 of the Columbia River water comes from Canada.

- **Canada has 15% of the basin area, but 30% of the 165 km^3 average annual flow at The Dalles.**

Why Did We Need a Treaty?

Bonneville Power Administration

- **Unregulated flow at the US-Canadian border has varied from 396 m^3/s to 15,600 m^3/s.**
- **Unregulated flow at The Dalles has varied from 1,000 m^3/s to 35,000 m^3/s.**

Why Did We Need a Treaty?

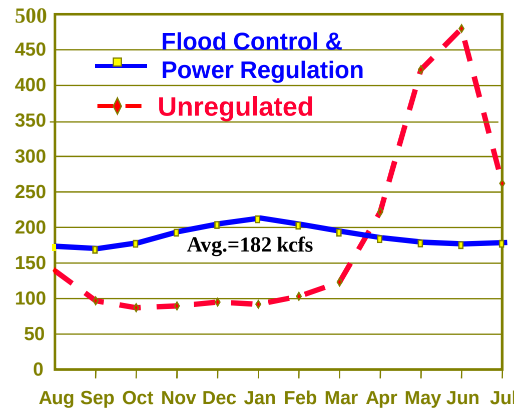
Bonneville Power Administration

- **For the 1948 Columbia flood flows at The Dalles, about 38% came from the Canadian Columbia/Kootenay basin, and 18% from the Pend Oreille basin, for a total of 56% crossing the Canadian border.**

Why Did We Need a Treaty?

Bonneville Power Administration

- **Comparison of 50-year Average Monthly Unregulated Flow to a Regulated Flow for Power/Flood Control at The Dalles in Kcfs.** **(1Kcfs = 28.3 m^3/s)**



Why Did We Need a Treaty?

Bonneville Power Administration

- **The Columbia River has large seasonal and annual variation in flow, and little storage compared to other basins.**
- **Year to year variation in average annual unregulated flow are unpredictable, and vary up to +46% to -41% from the mean at The Dalles.**
- **Total Columbia storage prior to Treaty about 16 km^3, today it is about 68 km^3 or 41% of annual flow.**

Why Did We Need a Treaty?

- **Canadian Treaty storage reduces flood flows, reduces spill, and shifts energy from low value time periods to high value time periods.**

How Did We Get the Treaty?

- **By 1959, after 11 years' work, including several proposals by U.S. companies to build dams in B.C., and difficult debates about benefits and alternatives, the IJC issued a report that recommended a Treaty with development plans and principles for apportioning the downstream benefits.**

How Did We Get the Treaty?

Bonneville Power Administration

- **Negotiations between February 1960 and January 1961 led to Prime Minister Diefenbaker and President Eisenhower signing the Columbia River Treaty on January 17, 1961.**

How Did We Get the Treaty?

Bonneville Power Administration

- **With strong support from the PNW, the Treaty was ratified by the U.S. Senate on March 16, 1961, but Canada wouldn't ratify.**
- **Province of British Columbia wouldn't agree; they needed money to build dams on both Columbia and Peace rivers; they wanted to sell the downstream power benefits to U.S. utilities, but the Canadian government was opposed.**

How Did We Get the Treaty?

Bonneville Power Administration

- **Detailed joint Canadian/U.S. engineering studies** during 1962-1963 estimated long term power benefits for a future sale.
- Negotiations between the governments led to a Treaty **Protocol**, signed January 22, 1964, clarifying some Treaty provisions, and a Canada/B.C. Agreement that allowed the sale of the Canadian Entitlement to the U.S.

Final Treaty Negotiations

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- Negotiations between Canada, British Columbia, United States government, and mid-Columbia utilities led to an agreement on a 30-year **sale of the Canadian Entitlement** to Columbia Power Storage Exchange, a consortium of U.S. utilities.
- **Exchange of diplomatic notes** implementing the Treaty and
the Entitlement sale were completed on Sept. 16, 1964.

Summary of 1964 Accomplishments

Bonneville Power Administration

- **PROTOCOL signed and Treaty implemented** September 16, 1964; Protocol clarified operations and benefit computations, and allowed the sale of the Canadian Entitlement to downstream power benefits.
- **CANADA-B.C. AGREEMENT** gave **construction/operation obligation** and benefits to British Columbia and **allowed sale** of Canadian Entitlement to U.S.

Summary of 1964 Accomplishments

Bonneville Power Administration

- **CANADIAN ENTITLEMENT SALE** to Columbia Storage Power Exchange (CSPE) Corporation for **$254 million** for a period of 30 years following the completion of each project. B.C. used the funds to construct their dams.
- **ALLOCATION and EXCHANGE AGREEMENTS allocated** Canadian Entitlement **obligations** among U.S. downstream project owners, & exchanged Entitlement with BPA to provide CSPE with fixed 30-year power.

Summary of 1964 Accomplishments

- **PACIFIC NW COORDINATION AGREEMENT** (PNCA) needed to assure coordinated operation of U.S. projects for optimum power to **create Entitlement**.
- **POWERHOUSE EXPANSION** of most main-stem Columbia projects **justified** by increased fall-winter flows from Treaty storage operation.
- **PNW-PSW INTERTIE justified** by transfer of Canadian Entitlement power to California, limited by PNW Preference Law – guaranteeing PNW utilities first right to PNW federal hydropower.

What Does the Treaty Do?

- The Treaty required Canada to construct and operate 15.5 Maf (of reservoir storage in the upper Columbia River basin at Mica, Arrow, and Duncan for optimum power generation and flood control downstream in Canada and the U.S.

Mica Dam

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Duncan Dam

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Power Administration

Keenleyside (Arrow Lakes) Dam

Bonneville Power Administration

What Does the Treaty Do?

Bonneville Power Administration

- U.S. paid Canada $64.4 million for one-half of the estimated future U.S. flood damages prevented through 2024, and must deliver to Canada annually one-half the estimated downstream power benefits generated at U.S. dams.

What Does the Treaty Do?

Bonneville
Power Administration

- The Treaty allowed the U.S. to construct and operate the Libby project with 5 Maf storage on the Kootenai River in Montana for flood control and other purposes. No benefit payments.

Libby Dam

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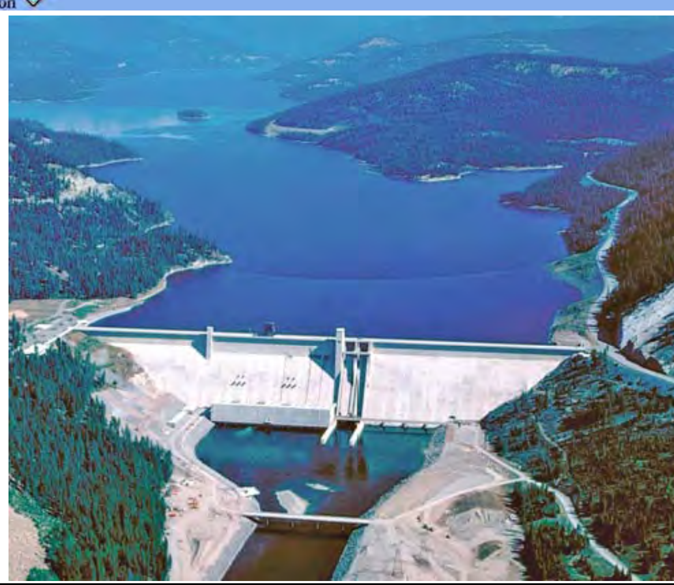


What Does the Treaty Do?

Bonneville Power Administration

- The Treaty is designed primarily to achieve hydropower and flood control benefits, and not for other purposes such as providing water for irrigation, navigation, recreation, or flows to assist fishery habitat or migration.

What Does the Treaty Do?

Bonneville Power Administration

- The Treaty preamble states:
  - "Being desirous of achieving the development of those resources in a manner that will make the **largest contribution to the economic progress** of both countries and to the welfare of their peoples of which those resources are capable, and
  - Recognizing that the greatest benefit to each country can be secured by cooperative measures for **hydroelectric power generation and flood control,** which will make possible other benefits as well. Have agreed as follows:"

What Does the Treaty Do?

Bonneville Power Administration

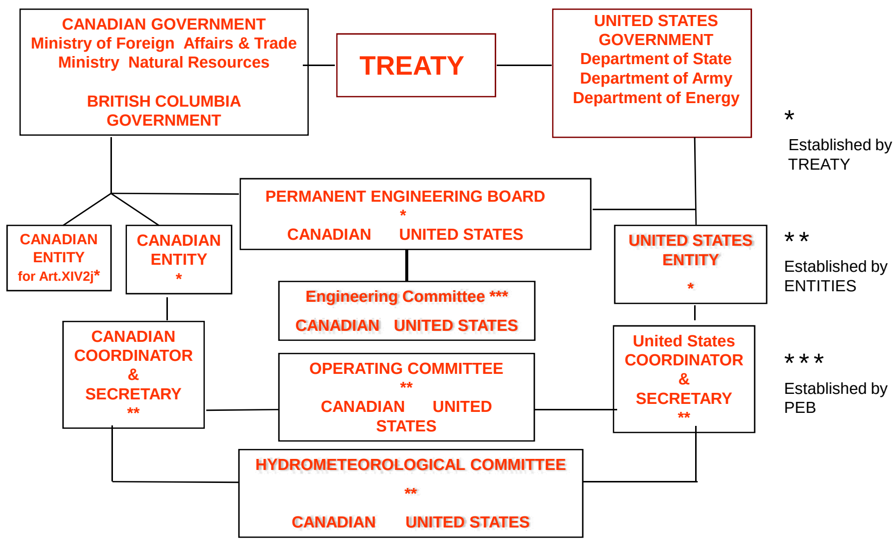
- Treaty Article III states:
  - "The USA shall maintain and operate the hydroelectric facilities included in the base system and any additional hydroelectric facilities constructed on the main stem of the Columbia River in the United States of America in a manner that **makes the most effective use of the improvement in stream flow** resulting from operation of the Canadian storage **for hydroelectric power generation** in the United States of America power system."
  - This obligation is discharged by reflecting this assumption in the default Treaty storage operating plans and downstream power benefit calculation.

Treaty Term

Bonneville Power Administration

- The Treaty has no end date. Either government has the option to cancel the Treaty after 60 years (2024) with 10 years advance notice. With termination:
  - Mica, Duncan, Arrow, and Libby may continue to operate subject to the 1909 Boundary Waters Treaty
  - Canada must provide flood control operation for the U.S. as long as need exists and projects exist, but US must pay Canada's operating costs and power losses
  - Canada may continue any Kootenay Diversions

Columbia River Treaty Organizations



Assured Operating Plan

- The Treaty requires the Entities jointly develop each year an Assured Operating Plan (AOP) for Canadian Treaty storage for the sixth succeeding operating year from hydro-regulation studies designed to achieve optimum power and flood control benefits in Canada and U.S.

Determination of Downstream Power Benefits

Bonneville Power Administration

- The AOP operating criteria is used to determine how much added usable power is generated downstream in the U.S. as a result of Canadian Treaty operations. One-half (1/2) of that power is the Canadian Entitlement.
- Canadian Entitlement payments are NOT affected or adjusted to reflect actual (real) power benefits each year.
- Current Canadian Entitlement is 482.8 average annual MW, delivered at rates up to 1241 MW, as scheduled by the Canadian Entity. Value to B.C., evaluated at $60/MWh, is about US$ 254 million per year.

Detailed Operating Plan

Bonneville Power Administration

- Treaty allows the Entities to jointly prepare and implement Detailed Operating Plans (DOP) that "may produce results more advantageous to both countries" than from operation under the AOP.
- The Entities and PEB have agreed that more advantageous results may include objectives other than power and flood control, e.g. fish, recreation, and dust storm avoidance, etc.

Detailed Operating Plan

Bonneville Power Administration

- Past practice has been for the DOP to authorize the Operating Committee to further agree within an operating year to supplemental operating agreements with mutually beneficial changes from the AOP operating data and procedures to meet current power and nonpower objectives.

Detailed Operating Plan

Bonneville Power Administration

- Actual Treaty storage operations are scheduled on a weekly basis and measured by flow at the U.S./Canadian border. This allows the Canadians the option to modify individual reservoir operations so long as the flow at the border is the same

Supplemental Operating Agreements

- Use of Canadian Treaty storage for U.S. non-power objectives is limited by the need for mutual benefits, so an annual agreement is uncertain because of the need for a "win-win" solution for the current situation.
- The annual Non-Power Uses Agreements between 1994 and 2007 have included 1 Maf storage for U.S. Biological Opinion Flow Augmentation and Vernita Bar minimum flows, while protecting Canadian Trout and White Fish and other Canadian non-power objectives.

Supplemental Operating Agreements

- Other SOA's have improved both power and non-power operations in both countries, e.g. fall storage.
- The Entities anticipate developing similar non-power agreements for 2008 and beyond.

Pacific Northwest Coordination Agreement

Bonneville Power Administration

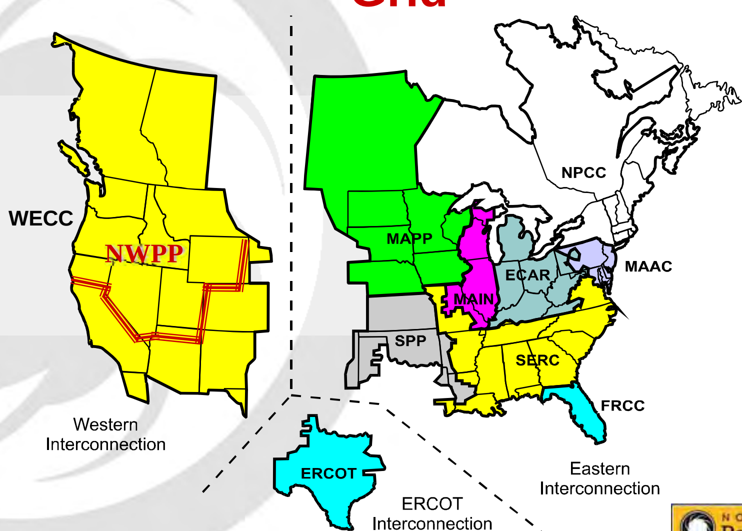
- The Treaty also spurred development of the U.S. Pacific Northwest Coordination Agreement (PNCA), which helps optimize the operation of Pacific Northwest projects to take advantage of improved water flows from Canada. Under this agreement, most Pacific Northwest hydropower projects operate as though they were owned by one utility, taking advantage of the regional diversity in stream flows and power loads, as well as the ability to optimize all reservoir storage operations to one power load. Sixteen parties, including the U.S. Army Corps of Engineers, the Bonneville Power Administration and the Bureau of Reclamation, are members of the PNCA.

Northwest Power Pool

Overview of the Northwest Power Pool

October 2002
Jerry D. Rust
Adapted by Dan Weston February 2009

North American Electric Power Grid



Northwest Power Pool

- **NORTHWEST POWER POOL** (NWPP) serves as a forum in the electrical industry for reliability and operational adequacy issues in the Northwestern U. S. and Western Canada
- NWPP promotes cooperation among its members in order to achieve reliable operation of the electrical power system, coordinate power system planning, and assist in transmission planning in the Northwest Interconnected Area.

Northwest Power Pool

- NWPP is a voluntary organization comprised of major generating utilities serving the Northwestern U.S., British Columbia and Alberta. Smaller, principally non-generating utilities in the region participate indirectly through the member system with which they are interconnected.

Northwest Power Pool

- The NWPP was originally formed in 1942, when the U. S. federal government directed utilities to coordinate operations in support of wartime production.
- NWPP activities are largely determined by major committees - the Operating Committee, the PNCA Coordinating Group, and the Transmission Planning Committee.
- Web Site: http://www.nwpp.org

NWPP PARTICIPANTS

- 7 U.S. States
- 2 Canadian Provinces
- Federal, Public, Private, Provincial Ownership
- International Boarder (Treaties associated with water)
- Non-Jurisdictional as well as Jurisdictional
- Preference Act– Public Law 88-552
- 160 Consumer-owned electric utilities
- 16 Control Areas (32 in the Western Interconnection (WI)).
- 62,149 Transmission circuit miles (53.7% WI)
- ~78,000 Megawatts Total Resources (44% WI)
- ~ 45% Winter Peak load of the WI
- ~ 45% Energy load of the WI
- Automated Reserve Sharing Agreement
- Hydro Coordination
- Hydro / Thermal Integration
  - ...ro located on
  - Thermal locat...

HISTORIC DATES

- 1923 - City of Seattle and Tacoma Interconnects
- 1942 - NWPP Operating Committee Formed
- 1956 - Bonneville Power Administration (BPA) interconnects with Idaho Power Company
- 1964 - Pacific Northwest Coordination Agreement (PNCA) signed
- 1968 - Columbia Storage Power Exchange and Canadian Entitlement Allocation
- 1980 - Northwest Power Act
- 1990 - Endangered Species Act
- 1997 - Renegotiate PNCA

NORTHWEST PowerPool

LOAD/RESOURCE ANNUAL PLANNING – EXISTING RESOURCES

- Resources - Capacity ~ 78,000 MW
  - *Hydro (60%)*
  - *Thermal & Other (40%)*
- Peak Winter Load ~ 53,000 MW
- Energy - Delivered ~ 325,000 GWh
  - *Hydro (40%)*
  - *Thermal & Other (60%)*

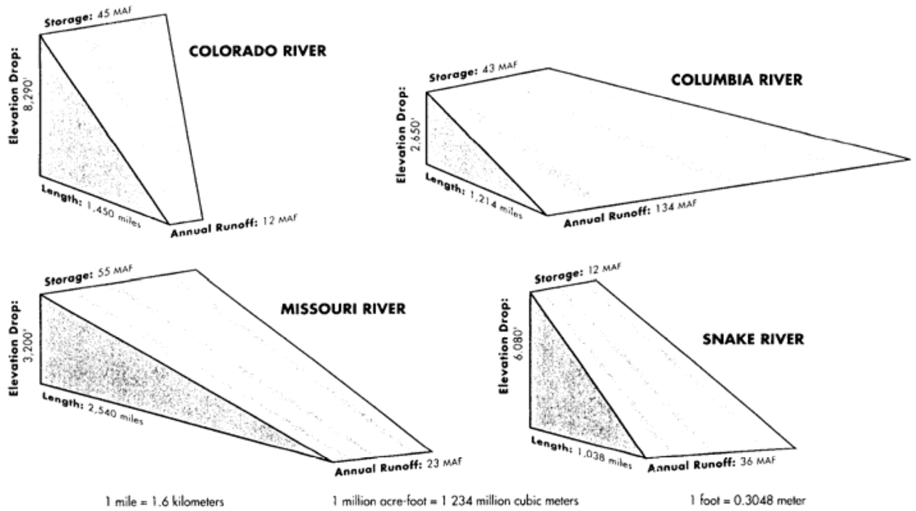
NORTHWEST PowerPool

LOAD/RESOURCE ANNUAL PLANNING – COORDINATION

- Two reasons to annually plan
- Coordination and Integration

LOAD/RESOURCE ANNUAL PLANNING – STUDIES

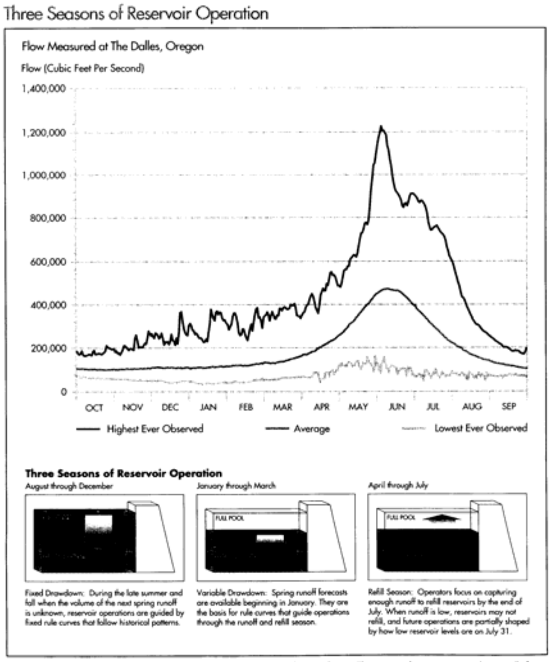
- Annual Planning Studies
    - *Maximize power production*
    - *Annual Planning period*
    - *Firm Energy Load Carrying Capability (FELCC)*
    - *Refill Requirements*
    - *Shifting and Shaping of FELCC*
    - *Reliability Standards meeting of firm load (Winter & Summer Assessments)*
    - *Integration of all Resources including maintenance*
    - *Outage Coordination (Transmission Facilities)*
    - *Address all non-power issues*
    - *Increase flexibility*



It is the large volume of water passing given points along the Columbia-Snake Rivers that is so valuable to river planners and users. Although the Columbia River total storage compares favorably with other large U.S. rivers, its runoff is significantly larger than its storage capacity as compared to the Colorado or Missouri which have annual flows less than storage capacity.

NORTHWEST PowerPool

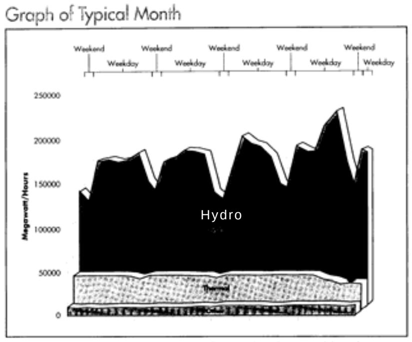
Three Seasons of Reservoir Operation



Operations on the Columbia River system are built around seasonal streamflow conditions. The water in the river can vary dramatically from month-to-month, depending upon precipitation and snowmelt.

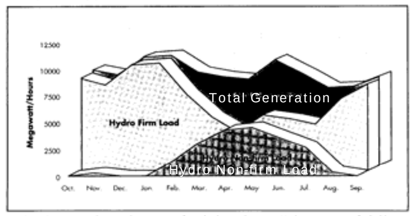
NORTHWEST PowerPool

Graph of Typical Month



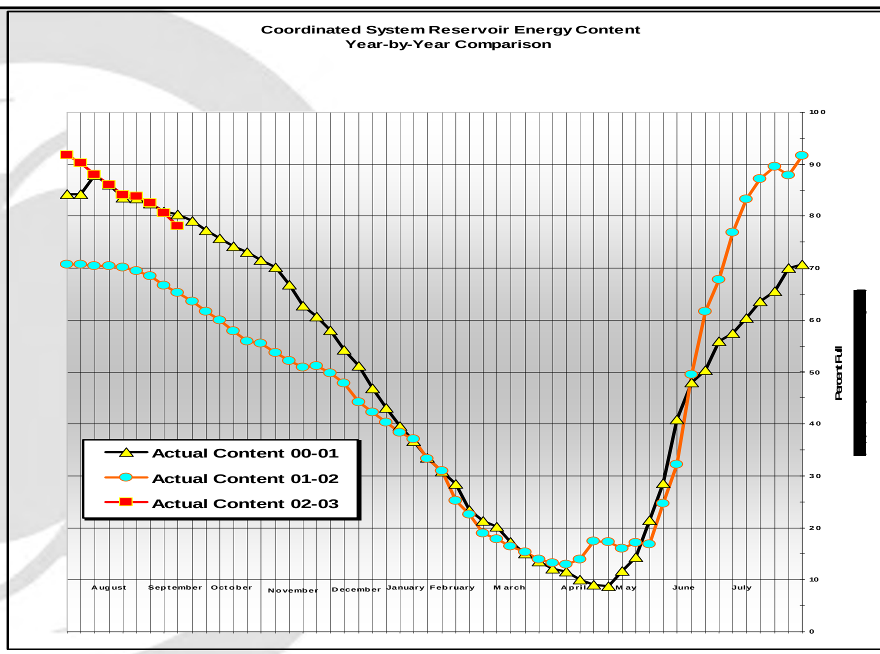
Loads are significantly lower on weekends, especially on Sundays, than on weekdays when most people are at work. The hydro system responds to changing loads, with thermal and other resources providing power to meet the relatively stable baseload.

Graph of Typical Year

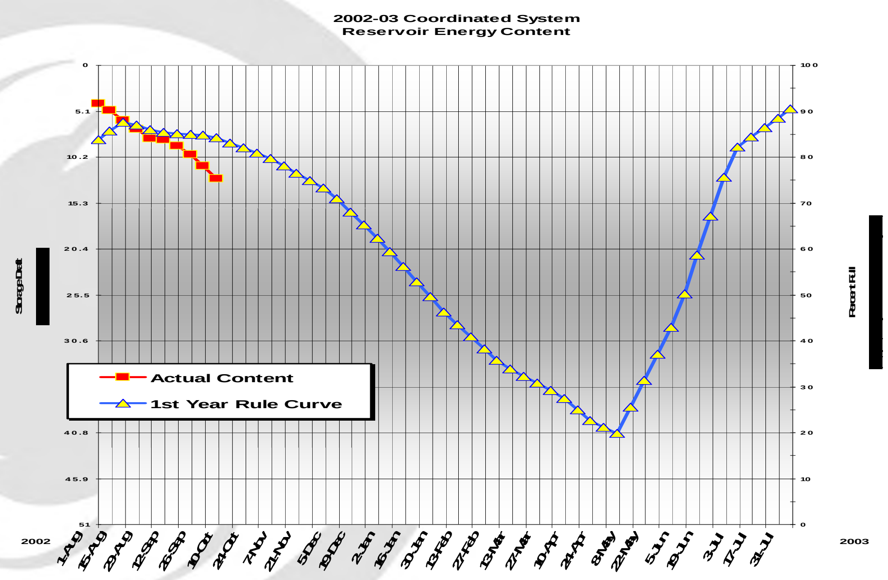


Loads and power production also vary significantly during the year. Hydro projects are fueled by water flows, which are higher during the spring and summer as snowpack melts. Loads are highest in the winter in the Northwest, as people turn up their thermostats to keep warm. Surplus energy can be either sold in the Northwest or sent to California, which has higher loads in the summer, and California utilities can send energy back to the Northwest in the winter, when we need it.

NORTHWEST PowerPool



NORTHWEST PowerPool



TODAY'S OVERALL EXPECTATIONS

Continue cooperation and coordination between the entities to ensure the reliability is maintained, if not enhanced, to meet current and future requirements of consumers in the area.

NORTHWEST PowerPool

QUESTIONS?

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BONNEVILLE
POWER ADMINISTRATION

Last Modified 29 Jan 2009

Introduction

Bonneville
Power Administration

The United States Department of Energy

Bonneville Power Administration (BPA)

– Dan Weston, RAS Design Engineer
  - 42 years engineering experience (21 years at BPA)
  - Seven years RAS design experience

What, Why, Who, Where of RAS

- To answer the following questions
  - What is a RAS?
  - Why do we have RAS?
  - Who has them?
  - Where are RAS systems installed?
  - What difference does RAS make to BPA?
  - How are BPA's RAS systems designed?

What is a RAS?

- Equivalent Meanings
  - SIPS = System Integrity Protection Scheme (IEEE)
  - SPS = Special Protection Scheme (NERC, others)
  - RAS = Remedial Action Scheme (BPA, WECC)
- Text Book Definition
  - Fast Automatic Control Scheme designed to mitigate a power system disturbance.

What is a RAS?

Bonneville Power Administration

- Text Book Definition:

  Fast Automatic Control Scheme designed to mitigate a power system disturbance.

  - **Fast** = Usually RAS schemes are designed to react quickly – faster than a person can react.
  - **Automatic** = Without human intervention. The RAS detects a predetermined condition and takes a predefined action to prevent something

What is a RAS?

Bonneville Power Administration

- Text Book Definition

  Fast Automatic **Control Scheme** designed to **mitigate** a **power system disturbance**.

  - **Control Scheme** = RAS usually opens or closes one or more breakers to change the power system characteristics.
  - **Mitigate** = reduce or eliminate a problem.
  - **Power system disturbance** = Unstable condition, high or low voltage, or line overload; unplanned outage.

What is a RAS?

Bonneville Power Administration

- "Cascading Outage"
  - A situation where one unplanned outage causes further stress to other power system components, eventually causing an additional outage, which then puts even more stress on the remaining elements. The process continues to the point that the whole interconnected power system disintegrates and A BLACKOUT occurs.
  - RAS is intended to avoid blackouts.

What is a RAS?

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- Examples of RAS
  - Special scheme to avoid overload on a line.
  - Automatic voltage control scheme at a substation.
  - Wide-area system to maintain system stability.
  - Any protection system specially designed for a particular application.
- What is NOT a RAS or SPS
  - Standardized line protection used on all similar lines.

Why do we have RAS?

Bonneville Power Administration

- To protect the power system.
  - Solve specifically identified power system control problems.
- To safely allow higher power transfer on a transmission line.
  - Allow higher transfers without risking a blackout.
- To maintain system reliability.
  - RAS increases overall system reliability.

Why do we have RAS?

Bonneville Power Administration

- To help balance load and generation after a loss of one or the other.
- To Increase Path Capacity ($) without building more power lines.

Who has RAS?

Bonneville Power Administration

- Almost every power utility has some form of special protective scheme somewhere on it's system.
  - Reactive controls
  - Automatic voltage control
  - Load shedding
  - Generation dropping

Where are RAS systems installed?

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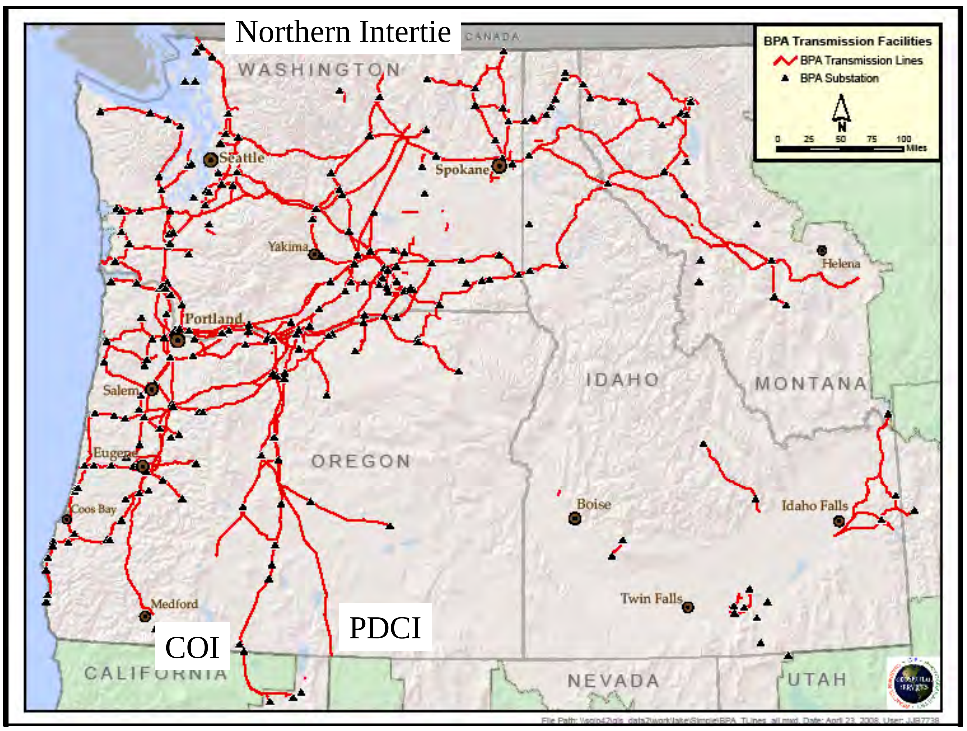
- Substations
- Generating stations
- Control Centers

What difference does RAS make to BPA?

Bonneville Power Administration

- Avoid system disturbances.
- Allow much higher operating transfer capability on interties.



BPA export capability with and without RAS

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Path (Export)	RAS Available (MW)	No RAS (MW)
California-Oregon-Intertie (COI) (N→S)	4800	1100
DC Intertie (PDCI) (N→S)	3100	1300
Northern Intertie (S→N)	2000	500

BPA import capability with and without RAS

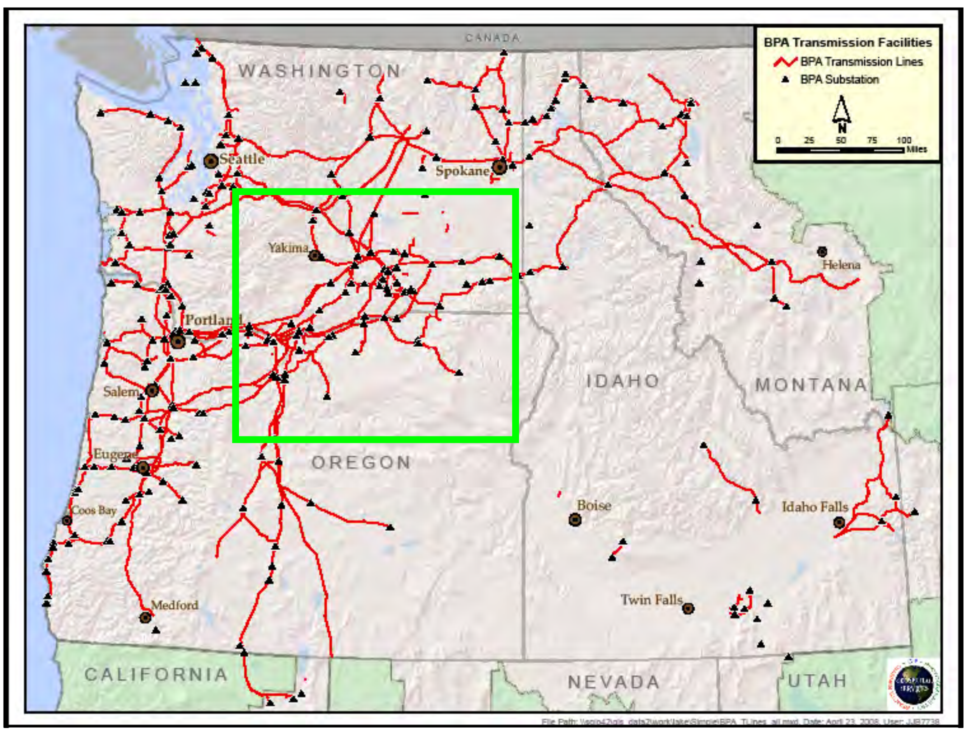
Bonneville Power Administration

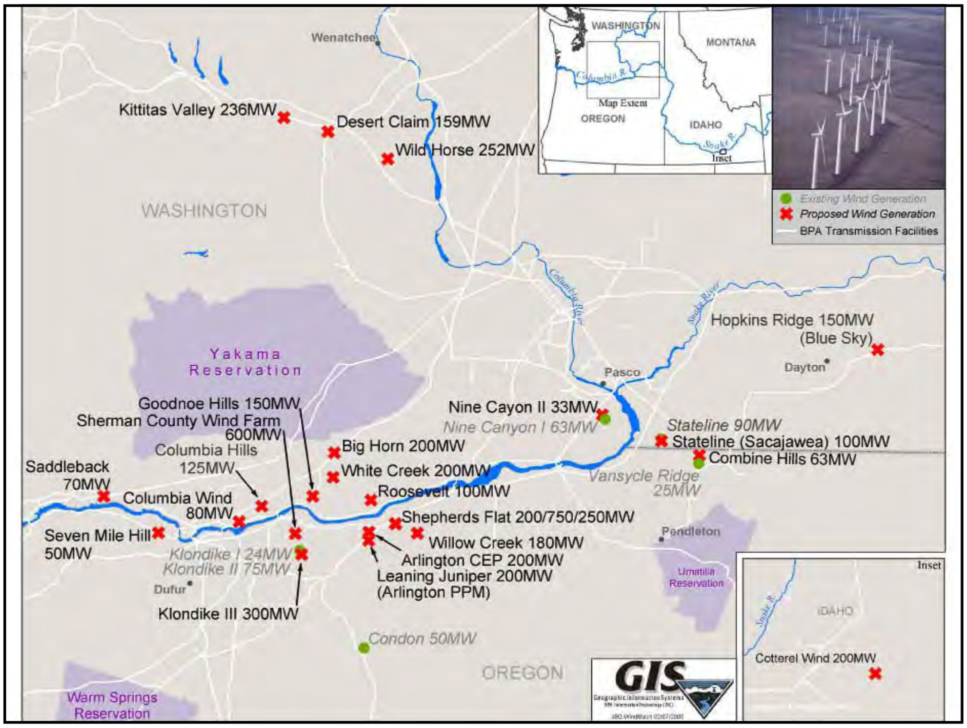
Path (Import)	RAS Available (MW)	No RAS (MW)
California-Oregon-Intertie (COI) (S→N)	3675	1000
DC Intertie (HVDC) (S→N)	2200	2066
Northern Intertie (N→S)	3150	800

Local versus wide-area RAS

Bonneville Power Administration

- BPA has two types of Remedial Action Schemes:
  - Local RAS – Schemes that do not impact the bulk transmission system. Limited in scope to one substation or a few substations.
  - Wide-Area RAS – Schemes that protect all or a large portion of the bulk transmission system. Must meet higher reliability requirements.





Local RAS Example

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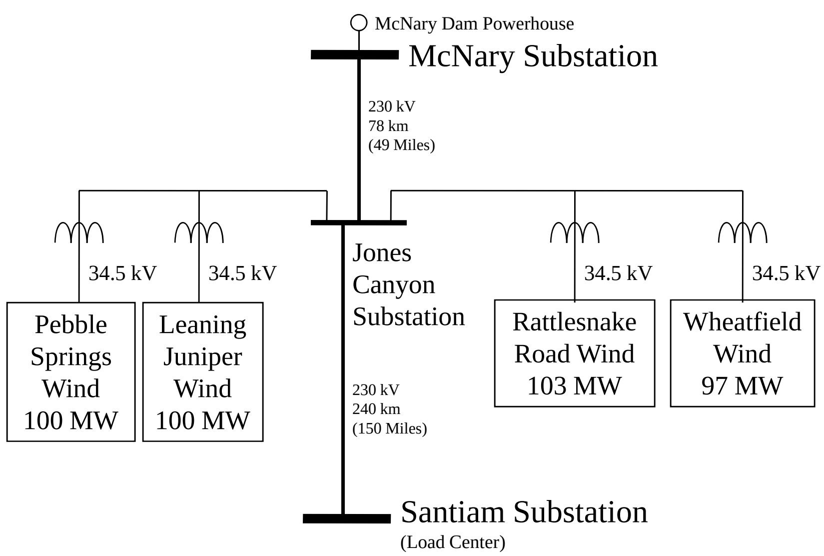
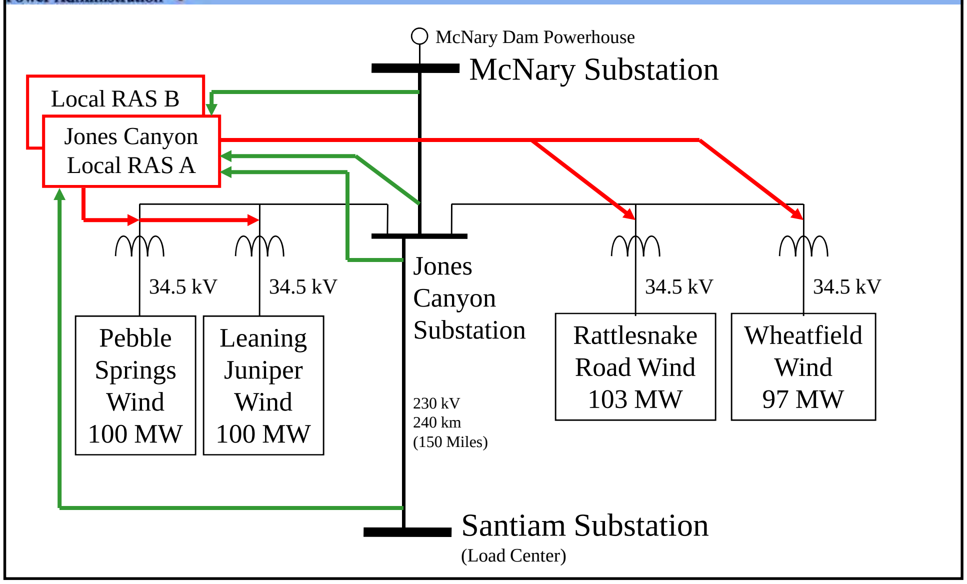


Local RAS Example

- Jones Canyon Substation
  - If the McNary-Jones Canyon line or the Jones Canyon-Santiam line open for any reason, immediately trip the wind generation sites off to allow line reclosing to operate.
  - If the Jones Canyon-Santiam line is over loaded for more than 5 seconds, send a warning signal to the wind sites. If still overloaded after 30 seconds, trip the wind sites off to try to eliminate the overload.

Local RAS Example



Wide-Area RAS Example

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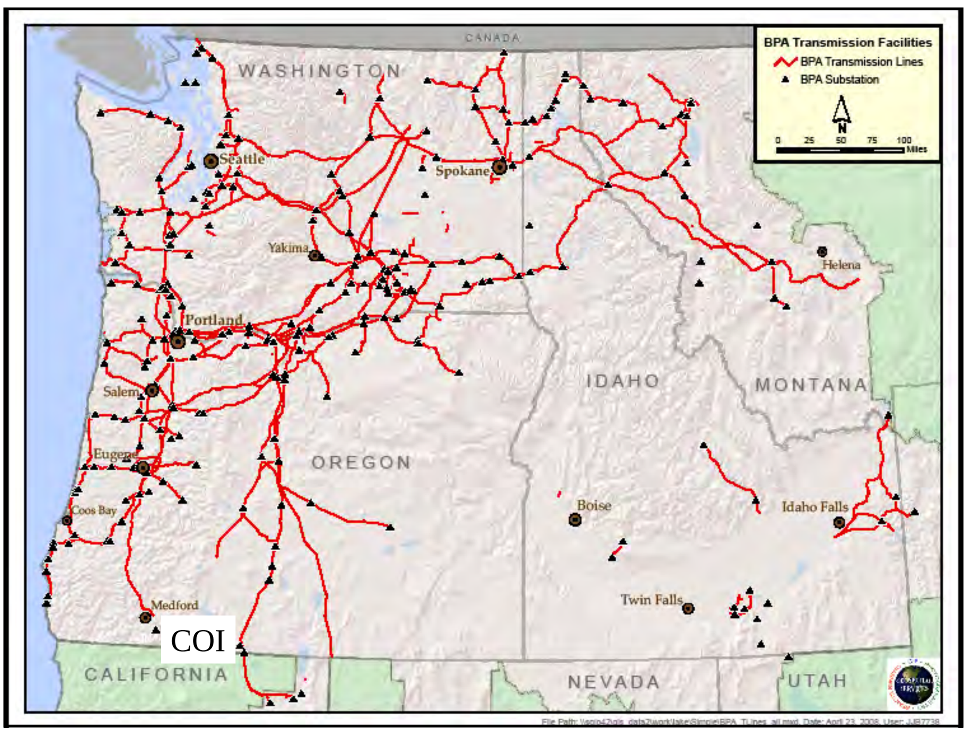
Power Administration

California-Oregon Intertie (COI) RAS

- •Central controllers (redundant), route inputs and outputs to and from that location.
- •Detect line outages related to the COI transmission lines.
- •If exporting power, insert the braking resistor and drop generation.
- •If importing power, drop interruptible loads.



Wide-Area RAS Example

Bonneville Power Administration

- Line-Loss Inputs (42 lines)
- Power-Rate Relay Inputs (5)
- Other (11)

RAS AC A Controller

- RAS Algorithms (16)
- Arming (105 points)

RAS AC B Controller

- Generation Dropping Outputs (29)
- Dynamic Brake Control Output (1)
- Reactive Control Outputs (10)
- Load Dropping Outputs (6)
- Other (14)

Wide-Area RAS Example

Bonneville Power Administration

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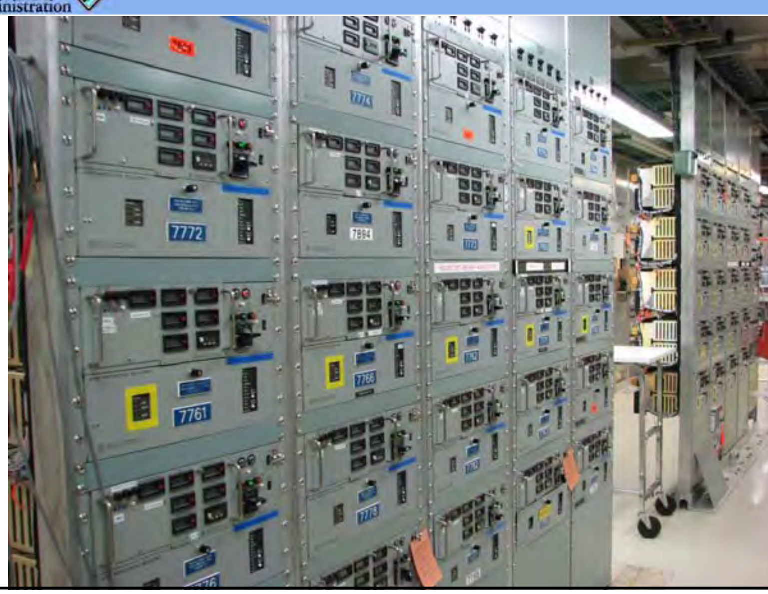
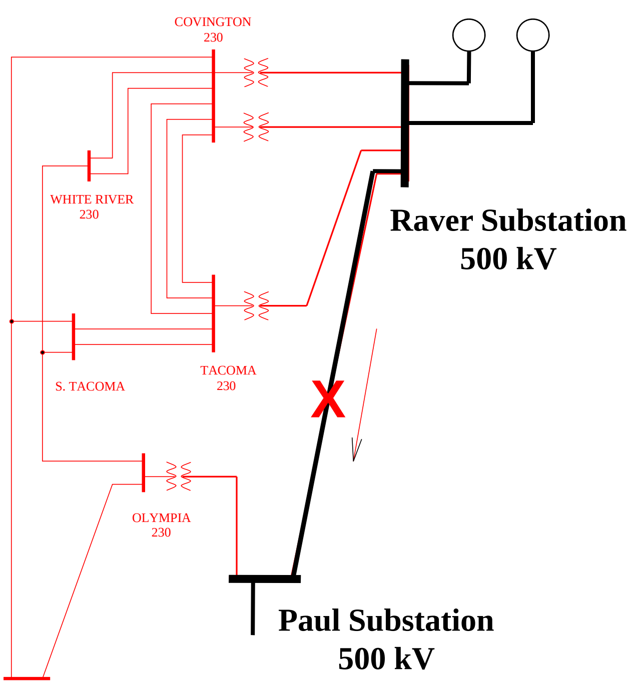


Types of RAS actions

Bonneville Power Administration

- BPA's Remedial Action Schemes are designed to relieve 3 types of power system problems.
  - Thermal (line overload) problems
    - Minutes to resolve
  - Voltage Stability
    - Seconds to resolve
  - Transient Stability
    - Milliseconds to resolve

Thermal RAS Example

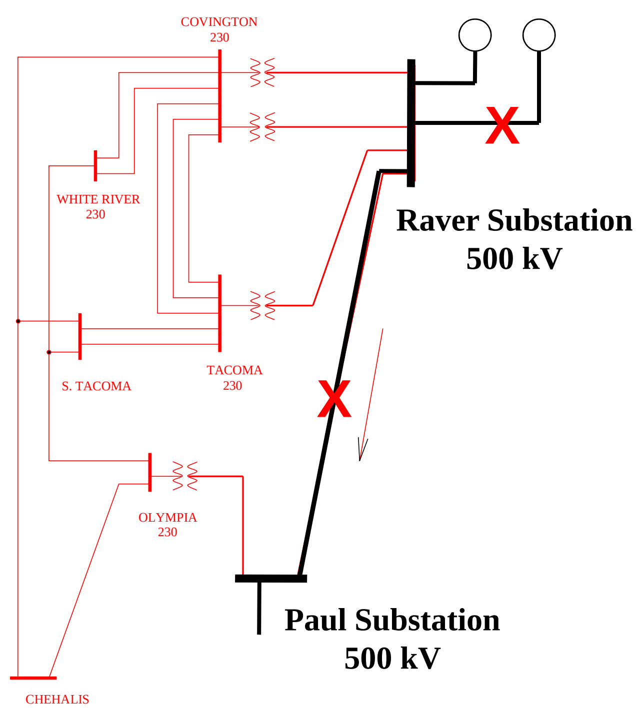


Thermal RAS - Example

Bonneville Power Administration

- Loss of the Raver-Paul 500 kV line causes thermal overloads on the underlying lower voltage transmission lines.
- Generator dropping north of the overloaded transmission lines is used to eliminate the overloads.

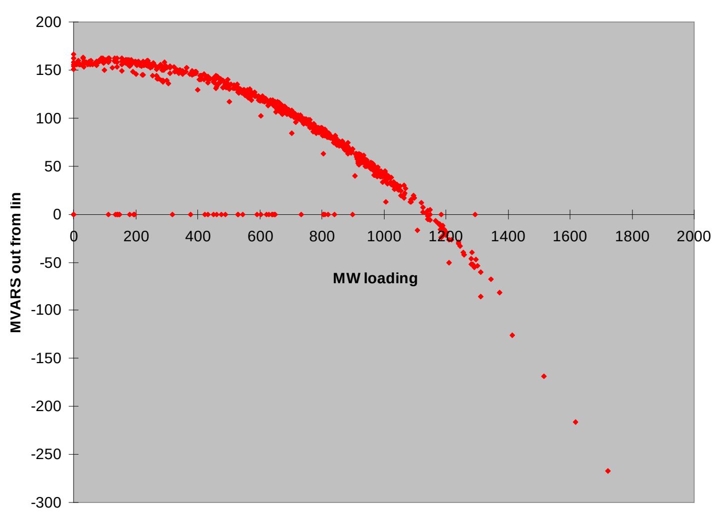
Thermal RAS Example



Voltage Stability Problem

- 500 kV transmission lines reach their surge impedance level (SIL) long before thermal problems. (see next slide)
- SIL typically reached at 800-1400 MW loading for a 500 kV line (thermal capacity is typically 2100-4000 MW).
- When a 500 kV line is loaded above it's SIL it acts like a reactor (pulls the voltage down) and put the system at risk of a voltage collapse if loading increases significantly.
- Switching reactive and dropping generation is used to maximize transfer capability

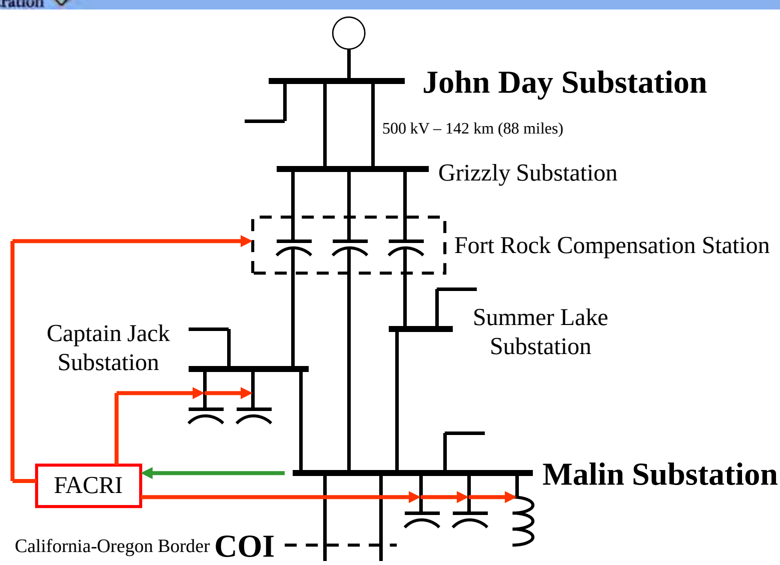
Surge Impedance Loading

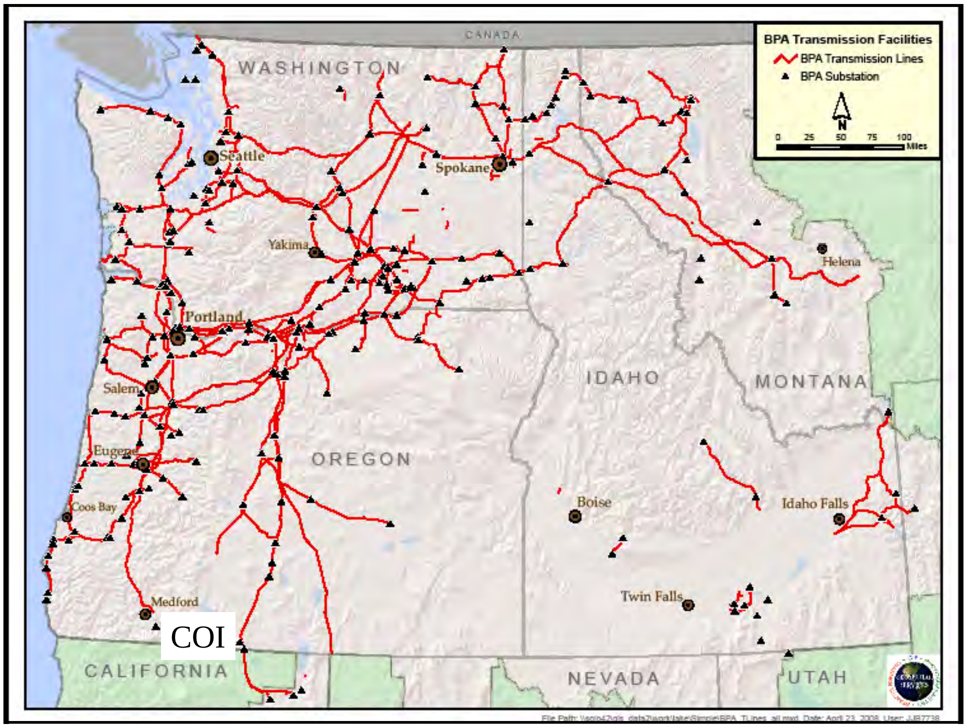


Voltage Stability RAS

- On long transmission lines reactance causes voltage problems before resistance heating causes thermal problems.
- This puts the system at risk of a voltage collapse if loading increases significantly.
- Reactive Switching is used to maintain transfer capability
- Example: Fast AC Reactive Insert (FACRI)

Voltage Stability RAS Example





Voltage Stability RAS Example

Bonneville Power Administration

- Fast AC Reactive Insertion (FACRI) RAS senses when the voltage at Malin drops below the normal range and initiates the switching of capacitors and reactors at Fort Rock, Malin and Captain Jack substations. This is intended to increase the voltage and prevent a voltage collapse on the COI following a disturbance to the south.

Transient Stability Problems

Bonneville Power Administration

- When large amounts of power are flowing across the system, any sudden change in the configuration can cause an unstable condition that will result in lines tripping due to out-of-step conditions.
- Fast remedial action response is needed (8-30 cycles) to maintain a stable system.

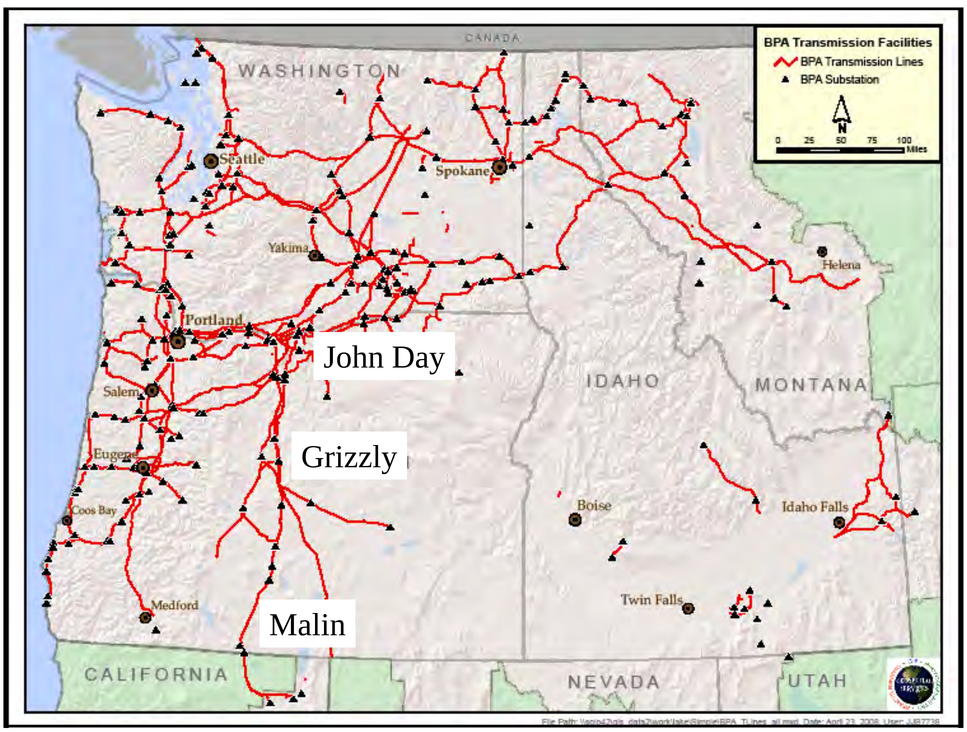
Transient Stability Problems

Bonneville Power Administration

- A large relative phase angle is needed to transfer large amounts of power across the system.
  - It is a function of the relative phase angle, receiving and sending end voltage, and system impedance.
  - A higher system impedance requires a larger angle to transmit the same amount of power.
- Loss of parallel transmission lines increases the system impedance and therefore the angle.
- Higher angle is an indication of higher system stress.
- Fast remedial action response is needed (8-30 cycles) to maintain a stable system

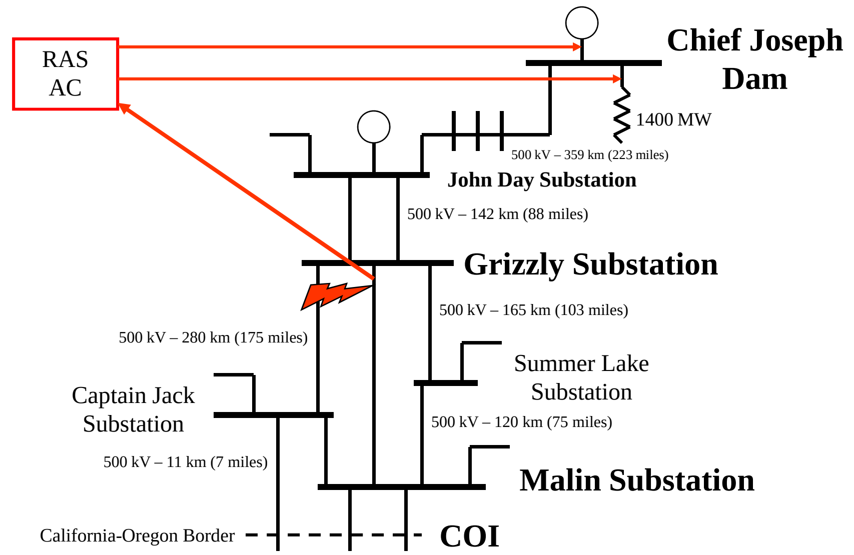
Transient Stability RAS Example

- If the California-Oregon Intertie is loaded near its capacity and a fault occurs on one of the major lines feeding the intertie, an unstable condition will occur.
- This unstable condition can be avoided by either dropping generation or by inserting the dynamic braking resistor.



Transient Stability RAS Example

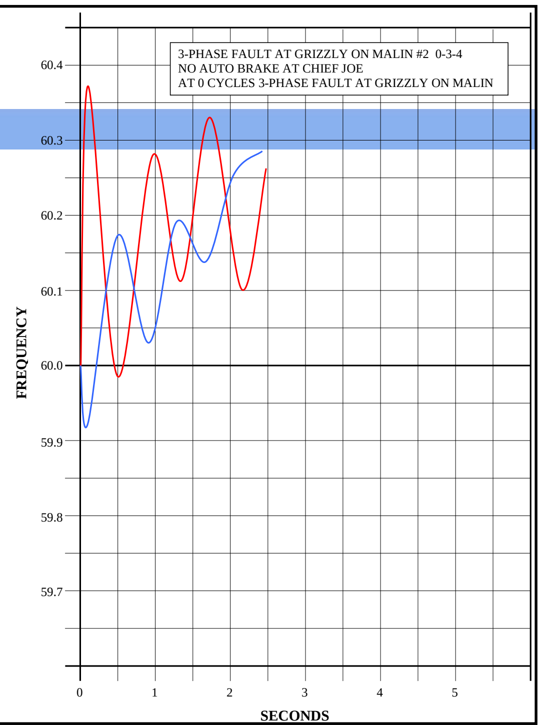
Bonneville Power Administration



Transient Stability

Bonneville Power Administration

- 3-phase fault at Grizzly with no RAS action.
- UNSTABLE

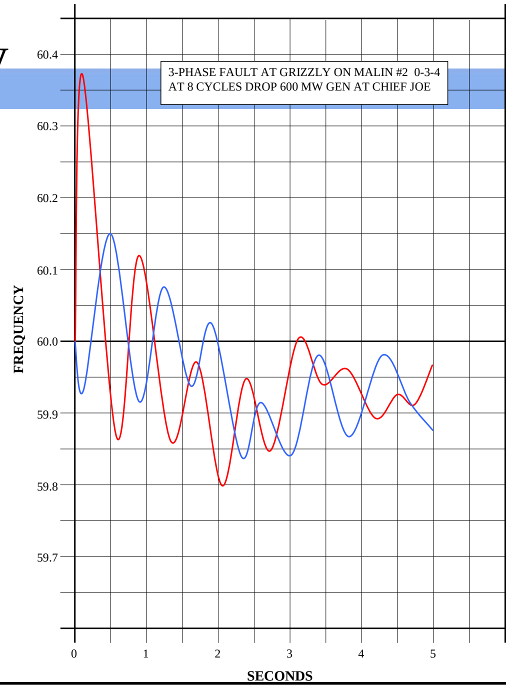


Red trace = BPA system frequency
Blue trace = Frequency south of COI
Power flow = 3200 MW N-to-S at COI

Transient Stability

Bonneville
Power Administration

- 3-phase fault at Grizzly with 600 MW gen drop at Chief Joseph.
- Stable with low frequency.

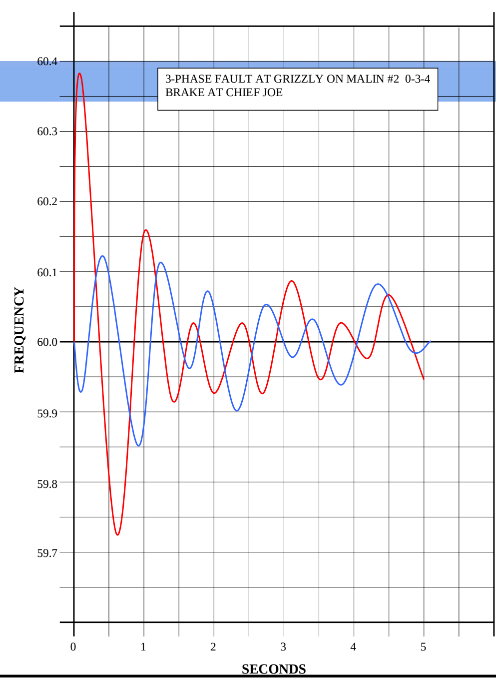


Red trace = BPA system frequency
Blue trace = Frequency south of COI
Power flow = 3200 MW N-to-S at COI

Transient Stability

Bonneville
Power Administration

- 3-phase fault at Grizzly with 1400 MW Chief Jo brake inserted for .5 seconds
- Stable and frequency normal



Red trace = BPA system frequency
Blue trace = Frequency south of COI
Power flow = 3200 MW N-to-S at COI

Export Contingencies

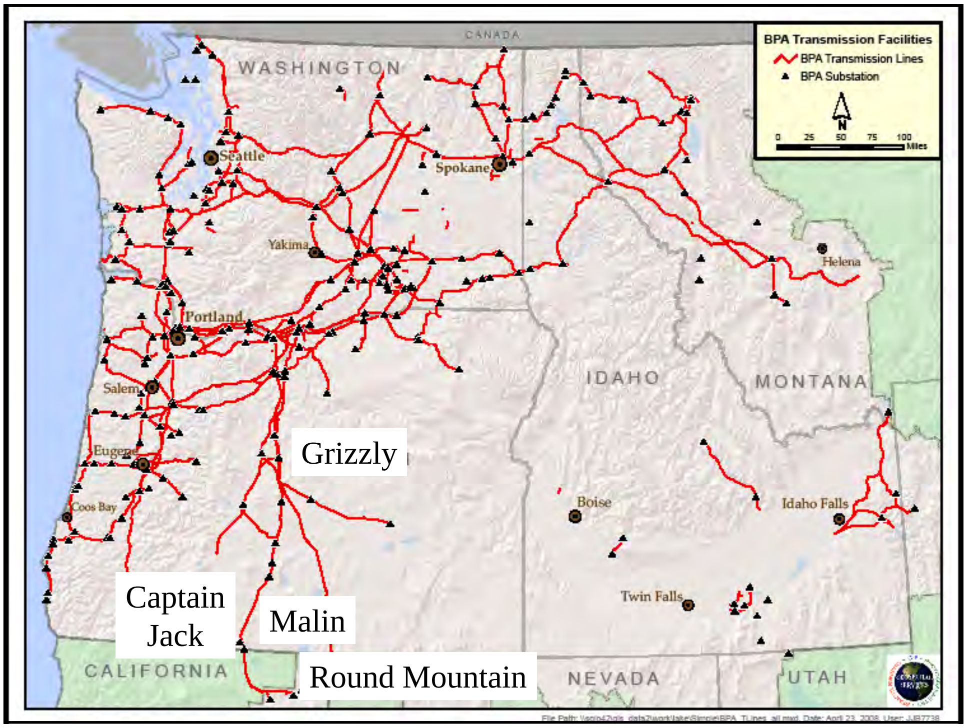
Bonneville Power Administration

- Power flowing out of the area (export).
- If the intertie opens, it is necessary to remove generation to maintain stability and keep generation equal to load.
- Enable (arm) generation dropping based on a nomogram or arming table developed through power flow studies.

Export Contingencies Example

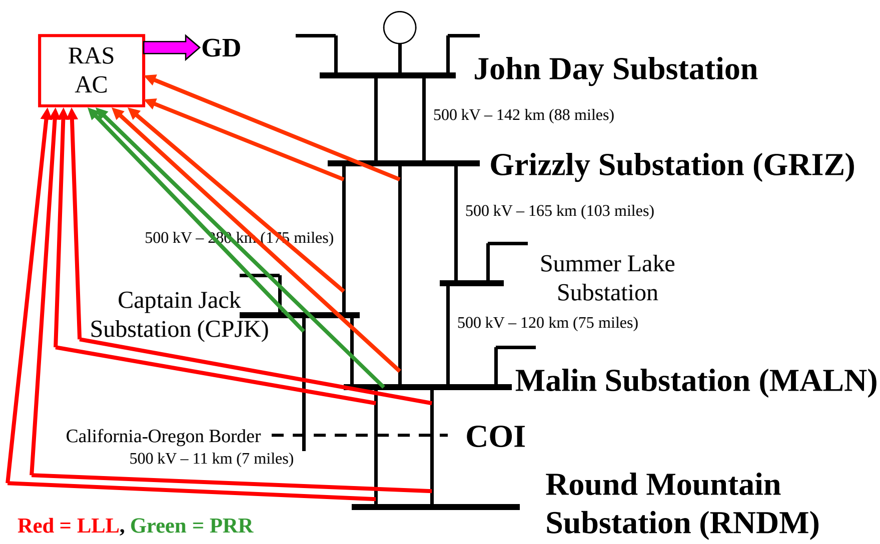
Bonneville Power Administration

- RAS AC Controllers monitor 42 line status indications (84 inputs).
- Each line status may contribute to the logic that determines if generation dropping is required.
- “High Gen Drop” and “Low Gen Drop” algorithms in the controller drop different amounts of generation depending on different contingencies.



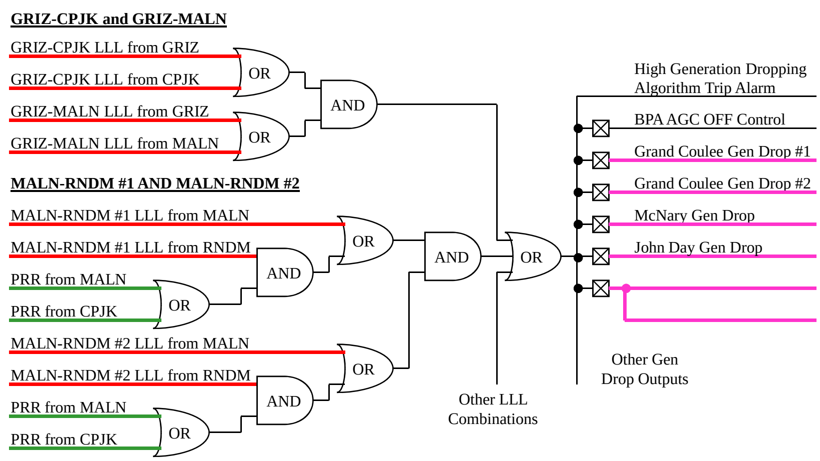
Export Contingencies Example

Bonneville Power Administration



RAS Algorithm Logic Example

Part of High Gen Drop Algorithm Logic



RAS Arming Table Example

HIGH GEN DROP			
COI	HIGH GEN DROP	COI + PDCI	HIGH GEN DROP
2800	300	4400	300
2900	600	4500	500
3000	900	4600	700
3100	1200	4800	900
3200	1500	5000	1100
3300	1800	5200	1300
3400	2100	5400	1500
3500	2400	7000	1600
3600	2700	7200	1700
4800	2700	7900	1700

Import Contingencies

Bonneville Power Administration

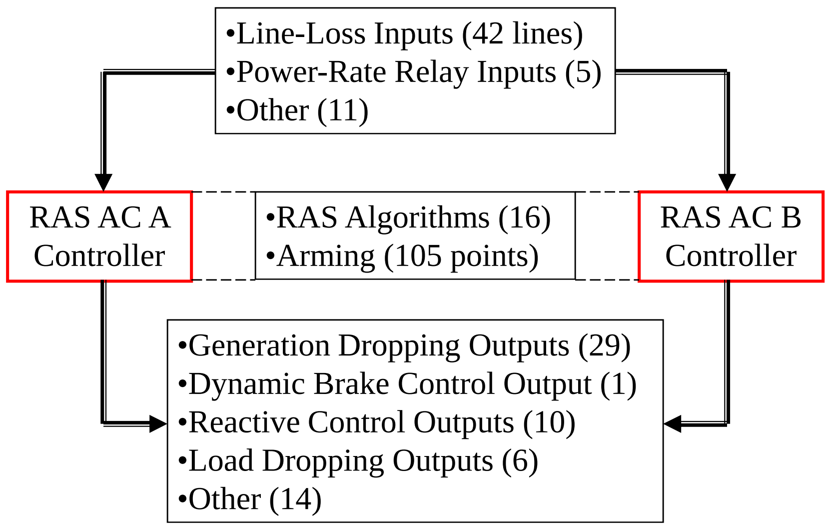
- Power flowing into the area (import).
- If the intertie opens, it is necessary to remove load to maintain stability.
- Arm load dropping based on a nomogram or arming table developed through power flow studies.
- Load Tripping
  - Aluminum Smelters
  - Light Industrial/Residential Load

Other RAS Outputs

Bonneville Power Administration

- Chief Joseph Brake (1400 MW Braking resistor)
- Reactive Switching
- Intertie Separation

Wide-Area RAS Example



Islanding

- In extreme conditions, break the interconnected system into stable “islands” that are self-contained.
- Better to break up in a controlled way than to have a blackout.

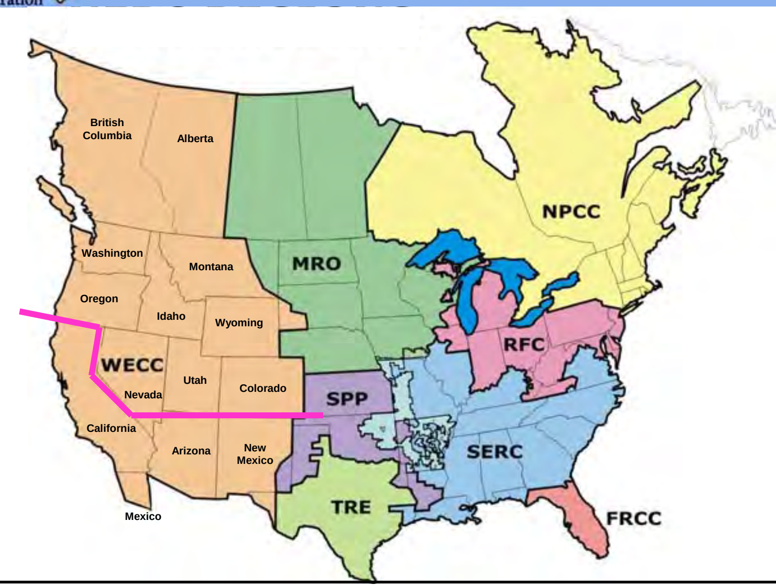
Example: NE/SE separation RAS

Bonneville Power Administration

- Total loss of the California-Oregon Intertie (COI) will initiate controlled separation
- The goal is to split the WECC system into two load/generation islands.
- With all lines in service, this is a safety net – we don't consider the loss of all 3 lines a credible event.
- Example: WECC NE/SE Separation RAS

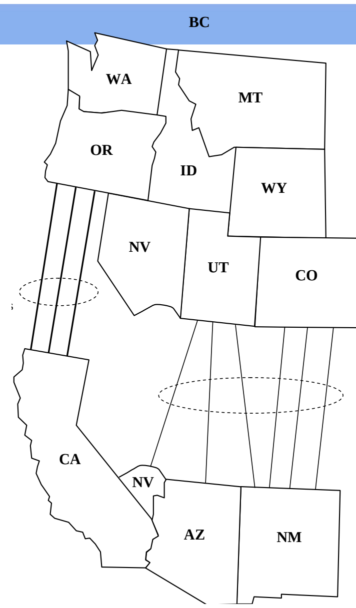
North American Electrical System Regions

Bonneville Power Administration



NE/SE separation RAS

Bonneville Power Administration



When is a RAS required?

Bonneville Power Administration

- Power flow studies determine the need for RAS.
- Studies must use consistent model of power system.
- WECC maintains a "base case" with a complete model of the WECC region.
- All WECC utilities use the base case as their model of the power system.

RAS Design Criteria

Bonneville Power Administration

- No single point of failure.
- Redundant, independent hardware systems (not primary/standby but identical and separate).
- Redundant, geographically separate communications paths.
- All equipment or communications failures must produce an alarm to the RAS dispatcher (fully monitored).

Peer Review

Bonneville Power Administration

- WECC RAS Reliability Subcommittee reviews and approves all RAS schemes in WECC.
- WECC RAS RS consists of representatives of each of the member utilities.
- Before a scheme is put in service it must be reviewed and approved by this committee.

WECC RAS Reliability Subcommittee

Bonneville Power Administration

- If we are to gain capacity from a RAS – it must not be credible to fail. The RAS is reviewed by the WECC RAS Reliability Subcommittee. If it is approved, then BPA can rely on that RAS for Operating Transfer Capability gains.
  - http://www.wecc.biz/documents/library/RAS/RAS_Approval_Procedure_04-2005.pdf

Testing Procedures

Bonneville Power Administration

- Before a new or modified scheme is put in service it must be thoroughly tested to verify that all components are working as designed.
- New communications equipment must undergo a 30-day "burn-in" period in an attempt to eliminate manufacturing defects.

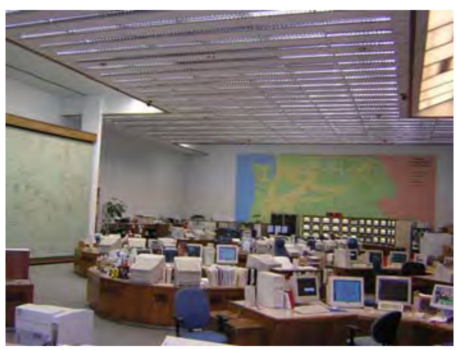
Dispatching RAS Schemes

Bonneville Power Administration

- BPA has a RAS dispatcher on duty 24 hours per day.
- RAS dispatcher duties are defined by “standing orders” – DSO’s
- There is a DSO defining the operation of each RAS.
- The dispatcher “arms” the RAS scheme according to the DSO for that RAS.

Dispatch Floor

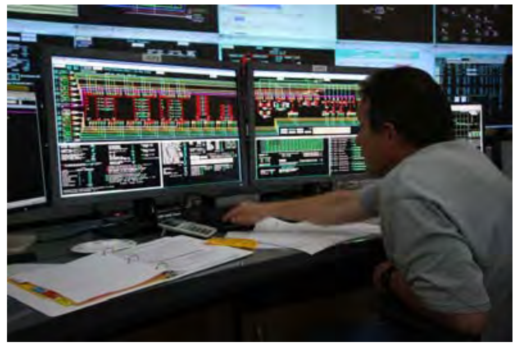
Bonneville Power Administration



BPA RAS Dispatcher

Bonneville Power Administration

- RAS Dispatcher at Dittmer Control Center.
- This desk is manned 24/365.

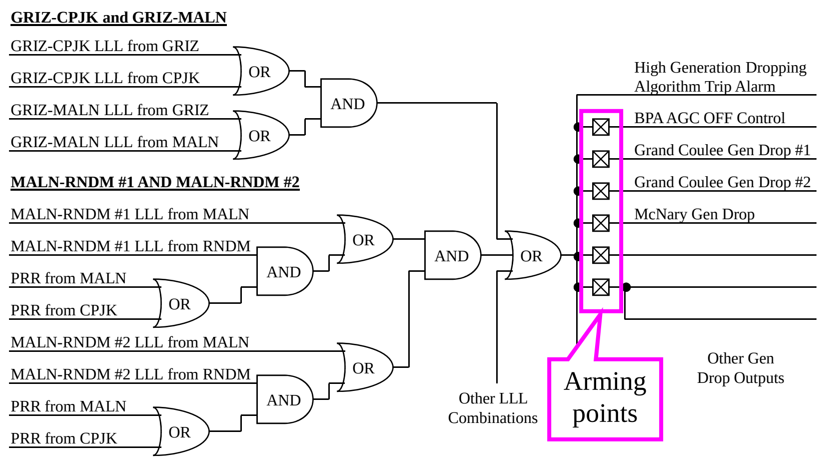


Arming of RAS

Bonneville Power Administration

- At BPA most arming is done manually by selecting a point on a display (SCADA).
- Most arming points are located within the RAS Controller.
- Some arming points at a remote sites, consisting of latching relays or logic within an “intelligent electronic device”.

RAS Algorithm Logic Example



Arming of RAS

- The BPA RAS dispatcher must keep track of hundreds of arming points – too many to do manually.
- A program on the BPA SCADA system keeps track of the arming points and compares them to the DSO criteria for that RAS. The program calculates the required arming level (in MW) for each algorithm on the RAS and displays that figure.

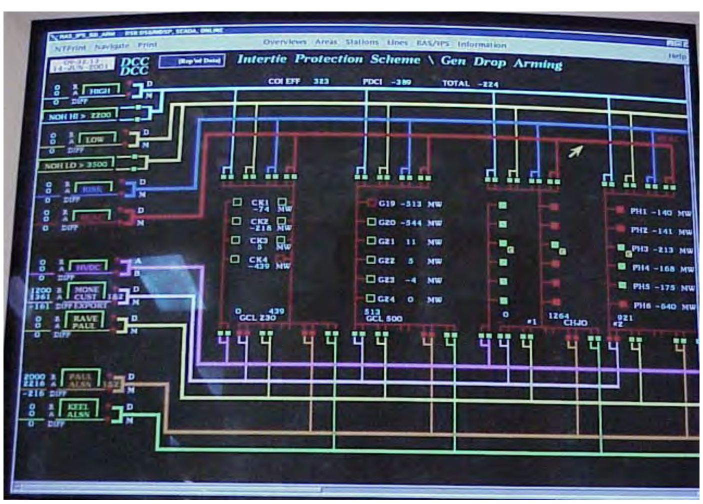
Arming of RAS

Bonneville Power Administration

- The actual armed MW value is also calculated and displayed.
- The dispatcher then must choose appropriate arming points to achieve the required arming level.
- If conditions change and the required arming level changes, an alarm sounds and the dispatcher is alerted to make an adjustment to the arming.

COI Gen Drop Arming Display

Bonneville Power Administration



Automatic Arming

Bonneville Power Administration

- For some RAS the arming is defined well enough that the computer can automatically arm the RAS and just alert the dispatcher when a change occurs.
- As RAS schemes become more complex, more automatic arming is being implemented.

Monitoring of RAS

Bonneville Power Administration

- One of the design criteria for a RAS is to completely monitor the equipment.
- The dispatcher must be alerted any time there is an equipment or communications failure that affects a RAS.
- Depending on the nature of the failure, maintenance personnel may be called out at any time to troubleshoot and repair.

Monitoring of RAS

Bonneville Power Administration

- Alarms are time-tagged with a time resolution of 1 ms.
- This allows after-the-fact analysis of RAS events to determine exactly what happened.

Record-Keeping

Bonneville Power Administration

- All RAS events are recorded in a log and the data is analyzed to verify if the RAS operated properly.
- Mis-operations are carefully analyzed to determine why the system mis-operated.
- There is a very limited amount of time to repair or modify if the RAS did not operate properly.

Reporting of RAS Mis-operations

Bonneville Power Administration

- Operating capability is reduced and monetary penalties may apply if not repaired in time.
- The NERC, and WECC must be notified immediately of all RAS mis-operations, what is being done to repair and when it is repaired.

BPA Unique Features

Bonneville Power Administration

- BPA power system is primarily transmission with very little distribution.
- Most other utility systems include distribution facilities.
- This will affect the nature of the required RAS systems.

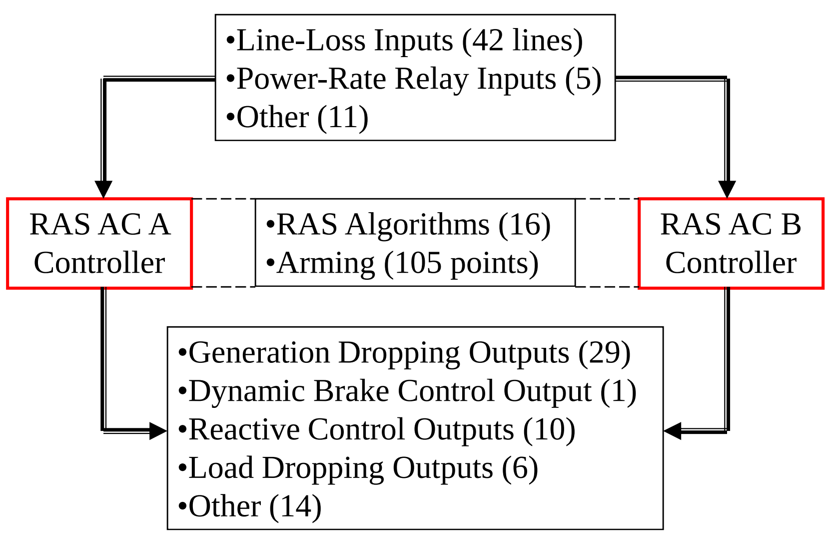
RAS System Components

Bonneville Power Administration

- Inputs
- Outputs
- Communications
- Monitoring systems (SER, SCADA)
- RAS Central Controllers
  - Local RAS
  - Wide-area RAS
- Wide-Area RAS Test system

Wide-Area RAS

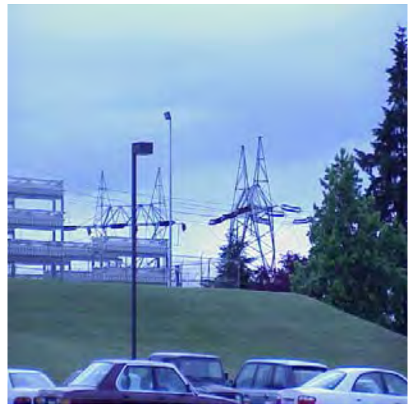
Bonneville Power Administration



RAS Inputs

Bonneville
Power Administration

- Inputs are received from:
  - Line Loss Detection Logic (LLL)
  - Power Rate Relays (PRR)
  - Other RAS systems
  - Other inputs



RAS Line Loss Detection

Bonneville
Power Administration

- Power Circuit Breaker Status (‘b’-switches).
- PCB trip bus voltage.
- Disconnect status (‘b’- switches)
- Maintenance switch / Relay selector switch.
- Avoid mixing RAS with other systems (protective relaying, SCADA, etc.).

Power, Voltage, Current Inputs

Bonneville Power Administration

- Some RAS schemes require sampling of the power, voltage or current values.
- Local schemes sample directly into the local controller (GE N60 UR).
- Wide-Area RAS may require telemetering values to the RAS controller.

Power-Rate Relays

Bonneville Power Administration

- Power-rate relays (PRR) are used to detect that a power system disturbance has occurred.
- The output of the PRR is used to supervise other inputs to avoid false trips.

Links between RAS systems

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- Sometimes it is necessary to use an input from another RAS to key a RAS.
- Should be avoided if possible in order to maintain independence and avoid maintenance and testing problems.

Other RAS Inputs

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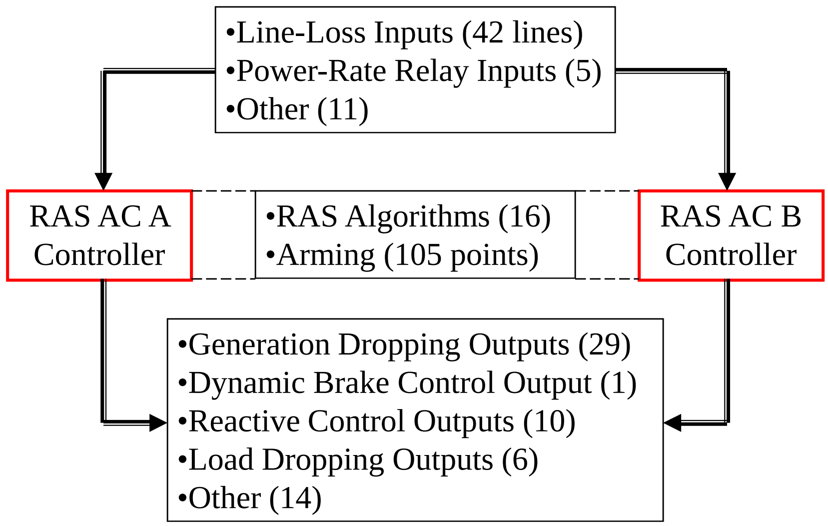
- Status of cutout or test switches.
- Intertie power flow direction indications.

Wide-Area RAS

Bonneville Power Administration



RAS Outputs

Bonneville Power Administration

- Generation Dropping.
- Chief Joseph Dynamic Braking Resistor.
- Reactive Switching.
- Intertie Separation.
- AGC Suspend to other utilities.
- Line Opening (thermal protection).
- Load Tripping.
  - Direct-Service Industries (Interruptible power)
  - Light Industrial/Residential Load

Communicating RAS Inputs/Outputs

Bonneville Power Administration

- Inputs and outputs are transmitted via transfer trip equipment.
- RFL 6745 and 9745 (obsolete).
- GE N60 Universal Relay (present standard).

RAS Communications

Bonneville Power Administration

- A and B systems use redundant, independent communication circuits (not just duplicate).
- Analog microwave (being phased out).
- Digital microwave, optical fiber.
- Digital SONET ring (path preference).
- Physical separation.
- Functional circuit availability requirement 99.95% (WECC)

RAS Monitoring

Bonneville Power Administration

- Sequence-of-Events Recording (SER) of alarms with 1 ms time resolution.
- Supervisory Control And Data Acquisition (SCADA) alarm points to alert dispatcher of failures.
- Central SER event database for RAS event analysis.

Local RAS Controller

Bonneville Power Administration

- Redundant systems (A and B).
- Local RAS usually has limited programming requirements.
- Programmable Logic Controllers (PLC)
- GE N60 present BPA standard.

Wide-Area RAS Controller

Bonneville Power Administration

- Larger programs
- More I/O
- Fault Tolerant
  - Triple Redundant
- Redundant Systems
- No single point of failure in either controller

Fault Tolerant

Bonneville Power Administration

- Triple modular redundant (TMR) hardware.
- Three of each component, voting two-of-three.
- One component can fail and the system continues to operate normally.

Parallel/Redundant Systems

Bonneville Power Administration

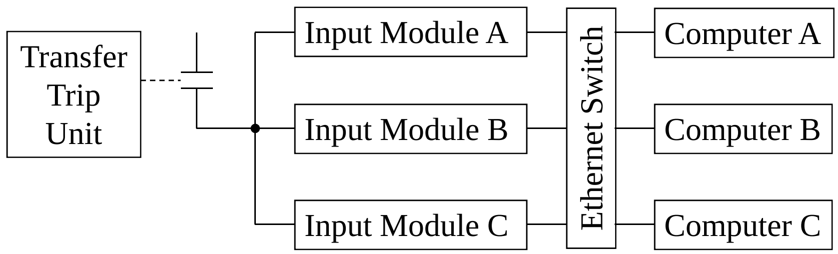
- Two separate systems (A and B).
- A and B systems completely separate – no common equipment.
- No single point of failure – multiple failures simultaneously are not considered to be a credible event.

Controller Inputs/Outputs

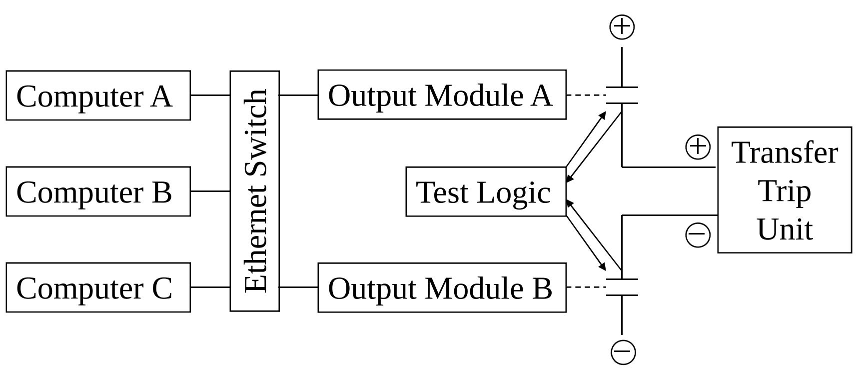
Bonneville Power Administration

- Solid-state I/O;
- Triple inputs, signals voted in software.
- “Guarded” outputs with automated testing.

Wide-Area RAS Inputs

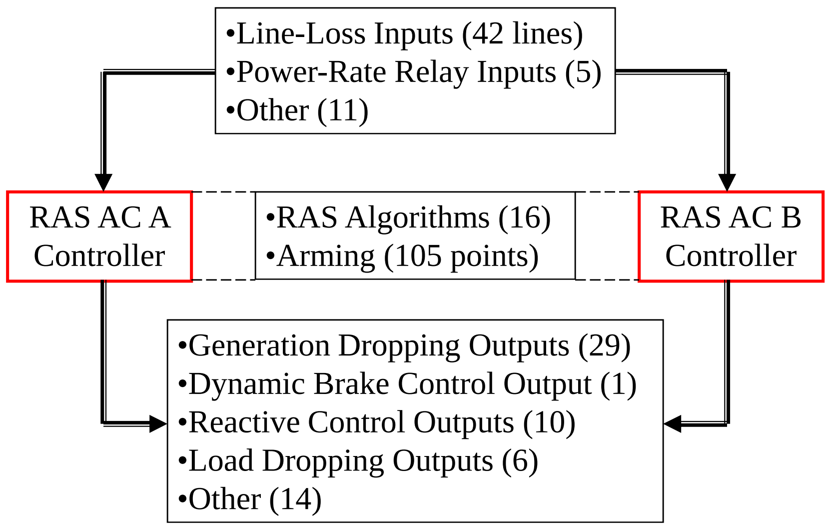


Wide-Area RAS Outputs



Wide-Area RAS Controller

Bonneville Power Administration



RAS System Testing

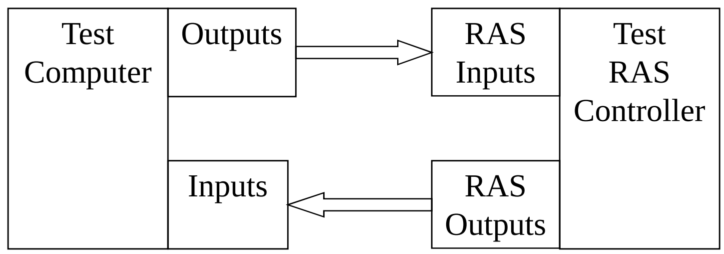
Bonneville Power Administration

- Designer does not test.
- Completed system tested by operations and maintenance personnel.
- Any time a change is made the entire system at the control centers is tested.
- The WECC & NERC requires utilities to test RAS annually.

Wide-Area RAS Test System

Bonneville Power Administration

RAS Automated Test System



Applying this to your system

Bonneville Power Administration

- Common power system model.
- Effect of loss of interties (failure modes and effects analysis).
- Multiple interties.
- Reliability requirements.

End of Presentation

Bonneville
Power Administration

Questions?

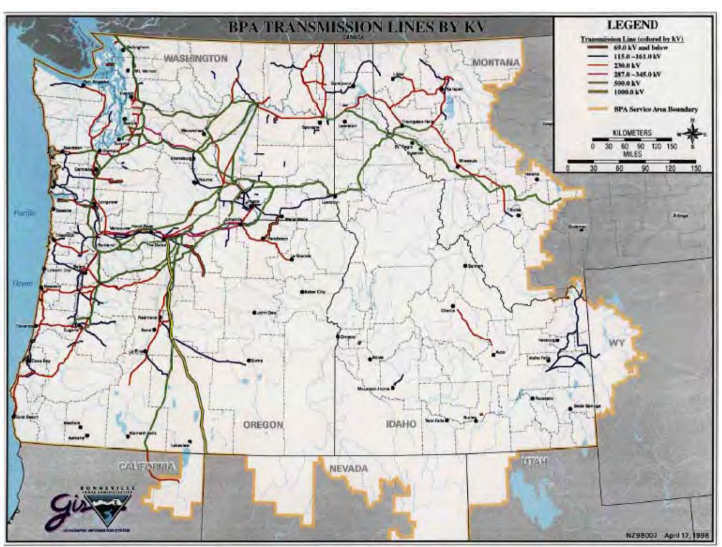
E-mail: wdweston@bpa.gov

Bonneville Power Administration

Morning Presentation
UF and UV Load Shedding
Substation Configuration
Fault Studies
2-20-2009

1

BPA Service Area



2

Under Frequency and Under Voltage Load Shedding

Power System Stability

- BPA is a participant in the underfrequency and undervoltage load shedding programs that are sponsored by the Northwest Power Pool NWPP.
- The Northwest Power Pool is a voluntary organization of Northwest utilities. The purpose is to promote cooperation among the NWPP participants to achieve reliable operation of the power systems in the Northwest.

Frequency Control

- Power system frequency is controlled mainly by the generation. Small frequency excursions occur continually as generation is controlled to match changing loads.
- The frequency is stable when generation and load match.
- Frequency is normally controlled by the following
  - Generator governors
  - Automatic generation control AGC
  - Dispatchers and power schedulers

5

Frequency Control

- Sudden changes in frequency occur as a result of a sudden change in a large block of load or generation. The loss of a major transmission path, intertie line, or large block of generation cannot be corrected using the normal means of generation control. The response is too slow. Other measures are necessary to control the frequency.
- Remedial action schemes RAS provide a faster response, and are the primary means to correct for sudden changes in the power system.
- RAS functions
  - Generator dropping
  - Load shedding
  - Insert series capacitors
  - Insert shunt capacitors
  - Remove shunt reactors at selected points in the system

6

Frequency Control

- Insert the dynamic breaking resistor
- Key transient excitation boost signals to some large hydro generators

- When these actions fail the system is in danger of having regional blackouts, or in the worst case, a total blackout.
- A final safety net is the underfrequency load shedding scheme.
  - BPA has determined that tripping 25 to 30 percent of its total load during an underfrequency event is adequate to prevent a larger outage.
  - In order to fairly distribute the burden of load shedding among the utilities, the blocks of load to be tripped are coordinated through the Northwest Power Pool NWPP.

7

Under Frequency Load Shedding

- Remedial action schemes require communications and data from throughout the power system.
  - Data is collected at the master control centers as inputs to the RAS programmable logic controllers PLCs.
  - The various RAS logic functions are programmed in the PLCs using the data from the remote sites.
- Unlike RAS, underfrequency load shedding UFLS is applied with discreet underfrequency relays at the locations of the load that is to be dropped.
  - UFLS relays operate independently and are in service at all times. These relays do not have remote enabling or disabling.
  - Auto-restoration is enabled at some locations.

8

Under Frequency Load Shedding

- Underfrequency relays across the system are set to drop pre-determined blocks of load at discreet frequency steps.
  - Load is dropped at 6 frequency levels ranging from 59.5hz to 58.6hz.
  - The trip delays typically are 30 and 60 seconds at the 59.5hz step.
  - At frequencies <59.3hz the blocks of load are tripped with no intentional delay.
    - Many of the relays use zero crossings of the voltage to calculate the frequency. During fault operations slight deviations in the zero crossings can occur. The relays are set to operate no faster than 4 cycles to be sure the measurement is correct.
    - Trip time is 4 cycles + Breaker trip time
  - Most loads are manually restored, however, auto restoration is also used.

9

Power System Voltage Stability

- Lowering of the bulk power system voltage can get to a point where normal voltage control can't recover the system voltage and a voltage collapse can result. This can lead to system blackouts and islanding.
- Voltage collapse occurs when there is not enough reactive power in an area to serve the reactive power requirements in that area.
- Voltage collapse is mainly a concern on western side of the power system.
- Voltage is normally controlled by the generators and by controlling the reactive power at selected points in the power system.
  - Shunt capacitors and lightly loaded transmission lines supply reactive power.
  - Shunt reactors and heavily loaded transmission lines consume reactive power.

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Power System Voltage Stability

- Shunt capacitors and shunt reactors are installed around the power system where voltage control is needed.
  - When the system voltage decreases shunt capacitors are inserted to supply reactive power and increase the voltage.
  - When the system voltage increases above the desired level shunt reactors are inserted to consume the excessive reactive power and reduce the voltage.
  - When portions of the 500kv grid are lightly loaded the longer transmission lines supply too much reactive power to the grid and the voltage rises excessively. Under these conditions certain predetermined lines are taken out of service for voltage control until the system load increases.

11

Power System Voltage Stability

- Power system factors that contribute to voltage collapse
  - The reactive power output of shunt capacitors is proportional to the square of the voltage across them (system voltage).
    - As the voltage collapses the MVAR output decreases. This contributes to the deficit of reactive power at that point in the system.
  - Transmission lines are capacitive at light loads and supply reactive power to the system. Since the line itself is an inductive reactance, there is a loading point where the MVARs consumed by the line inductive reactance equals the MVARs that are supplied. This is the surge impedance loading of the line SIL. Beyond this load level the line will consume reactive power contributing to voltage collapse.
  - Controlling voltage by changing taps on power transformers can work, but this may also force the reactive power out of the main grid into the distribution system and actually contribute to the reactive power deficit.

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Power System Voltage Stability

- In the Northwest voltage collapse is usually triggered by a power system event.
  - Under some conditions if a key transmission line is tripped due to a line fault a reactive power deficit can occur as the reactive power flow is redistributed to other lines.
    - This is mainly a concern in the western portion of the grid West of the Cascade Mountains.
  - When the voltage collapse event is too severe and can no longer be controlled, load must be shed in order to prevent a cascading outage.

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Under Voltage Load Shedding

- Under voltage load shedding is accomplished by discrete undervoltage relays.
- The relays are located in the load areas where studies indicate that a possible voltage collapse problem exists.
- The undervoltage relays are set to operate between 0.9pu to 0.92pu of the nominal system voltage. All three phase voltages are monitored and the relays operate on a three phase undervoltage.
- A voltage collapse event is a relatively slowly evolving event.
  - The relays are set to operate at three different time delayed levels. The trip times are 3.5 seconds, 5 seconds, and 8 seconds.

14

Recovery From a Blackout

Recovering the Power Grid After a Blackout

- The power grid is divided into several load / generation islands.
- Designated substations are equipped with dead bus clearing and remote synchronizing equipment.
  - The load / generation islands will be synchronized at these locations.
- In the event of a blackout SCADA will
  - Open all of the breakers at the designated substations using the dead bus clearing scheme.
  - Separate from other utilities.
  - Start generation and restore loads in the islands.
  - Synchronize the islands with the remote synchronizers.
  - Restore the rest of the system.

Recovering the Power Grid After a Blackout

- The dead bus clearing scheme allows scada to quickly open all breakers at a substation.
  - This scheme is supervised by voltage relays such that the command cannot operate unless the station is verified to be de-energized.
- The remote synchronizing scheme allows a scada operator to select lines to be synchronized at the remote substations.
  - Instrumentation transducers give the scada operator the voltage on both sides of the breaker, the frequency, and the frequency difference across the breaker.
  - When the frequencies (slip frequency) and voltages are within the operating band of the synchronizer, the synchronizer will be enabled and the line will be synchronized.
    - The synchronizer has an operating voltage band, a fixed phase angle window, and a dynamic synchronizing element.

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Typical BPA Substation Bus Configurations

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BPA Transmission System

- Voltage Levels and Approximate Circuit Miles
  - 500 kV ………..4734 mi., 7618 km
  - 230 kV ………..5300 mi., 8529 km
  - 115 kV …………3557 mi., 5724 km
  - 345 kV, 287 kV, 161 kV, 138 kV, and voltages below 115 kV …1333 mi., 2145 km

BPA Substation Configurations

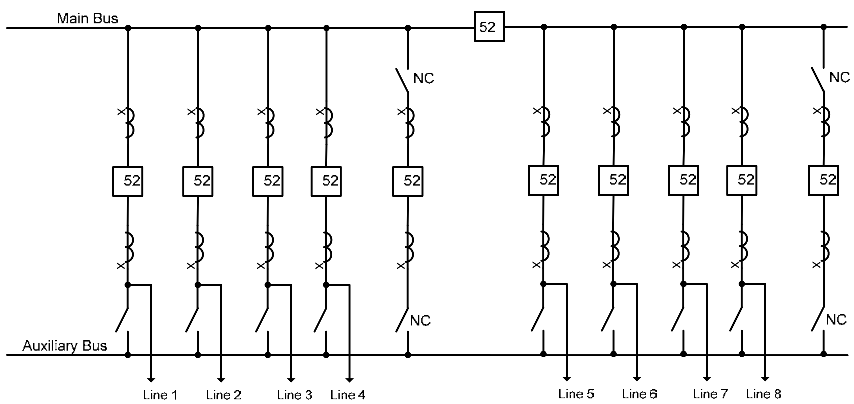
- BPA owns all, or a major portion of approximately 259 substations
- BPA uses three basic substation configurations in the transmission system.
  - Most older 115kV and 230kV substations have a Main bus / Transfer bus arrangement.
  - Some smaller substations are arranged in a ring bus configuration
  - 500kV substations and newer substations at the other voltage levels are arranged in a 1 ½ breaker arrangement
    - A modified ring bus is arranged such that as lines are added the station will evolve into a 1 ½ breaker configuration.

BPA Substation Configurations

- Main Bus / Transfer Bus (Auxiliary bus)
  - Each line is connected to the main bus by a circuit breaker and is connected to the transfer bus by a disconnect.
    - Each line has a dedicated circuit breaker.
    - The transfer bus disconnects are normally open.
    - The main bus and the transfer bus are connected together by a bus tie breaker.
    - The bus tie breaker allows a line to remain in service when its dedicated circuit breaker is taken out of service for maintenance. This is done by closing the transfer bus disconnect and transferring the line to the bus tie breaker. The line breaker is then taken out of service.

BPA Substation Configurations

- Main Bus / Transfer Bus (Auxiliary bus)



BPA Substation Configurations

- Main Bus / Transfer Bus Issues
  - Bus faults and breaker failure operations trip the main bus breakers and therefore open all lines that are connected to it.
  - As more lines are added to the buses the main bus is split into one or more sections with bus sectionalizing breakers.
    - Source lines (generation) and load lines are arranged in the bus sections to minimize the impact on the system for a loss of a bus section.
  - As system loading increases the loss of more than one bus section in the larger substations can have an adverse impact on the power system.
    - A failure of a bus sectionalizing breaker will result in the loss of two bus sections and cannot be tolerated.
      - In larger substations where the loss of more than one bus section is not tolerable an additional circuit breaker is added in series with each sectionalizing breaker. This will minimize the probability that a failed bus sectionalizing breaker will result in the loss of two bus sections.

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BPA Substation Configurations

- Main Bus / Transfer Bus Issues Continued
  - The protective relays on the bus tie breaker must be capable of operating on any line in the bus section.
    - Microprocessor based relays use multiple setting groups.
      - A relay setting selector switch is used to change setting groups when a line is bypassed.
    - BPA updated bus tie relays from electromechanical relays to microprocessor based relays when multiple setting groups became available.
  - Transfer trip signals from the remote terminal must be switched from the line relays to the bus tie relays.
    - A relay transfer switch is added to each line terminal for this purpose.

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BPA Substation Configurations

- Ring Bus Configuration
  - For smaller substations where future expansion is limited a ring bus is more economical.
    - These configurations are common configurations for substations that feed large industrial loads.
    - These configurations are also used at some substations where generation such as from wind farms and combustion turbines is integrated into the BPA system.

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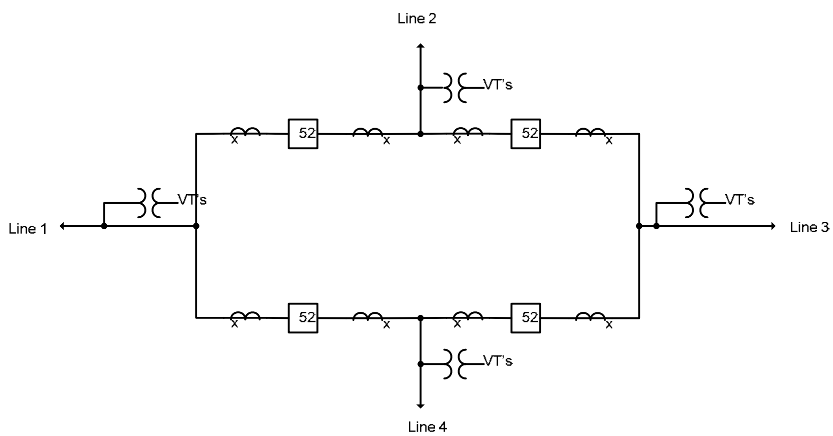
BPA Substation Configurations

- Ring Bus Configuration



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BPA Substation Configurations

- Ring Bus Configuration Issues
  - Ring bus advantages
    - Economical – one breaker per line
    - Breakers can be taken out of service one at a time for maintenance and the lines can remain in service.
    - No bus differential
    - Breaker failure operations only affect lines on both sides of the failed breaker.
  - Ring bus disadvantages
    - Not practical for larger substations
      - If the ring is open for any reason such as for breaker maintenance, a normal line fault operation can cause problems with other lines by opening the ring in a second, non-predictable location.
    - Reclosing can be difficult to coordinate.
      - Older protection schemes use breaker oriented reclosers. Lines on different sides of a breaker may have different reclosing requirements.
      - Newer microprocessor based relays solve this problem by including line oriented reclosing in the line relay.

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BPA Substation Configurations

- 1 ½ Circuit Breaker Configuration
  - 1.5 breakers per line terminal
  - Easily expanded by adding additional bays
  - 2 buses with associated bus differential relays
  - Source and load lines are arranged in the bays such that the loss of any bay will not create a system stability problem.
    - Breaker maintenance can create this problem. If a bus breaker is out of service, and a line fault occurs on the line that is connected to the opposite bus, both lines in the bay will be opened during the fault clearing interval.
- The 1 ½ breaker bus is currently BPA's standard bus arrangement. At smaller substations these buses are generally built as modified rings with future expansion to a 1 ½ breaker bus.

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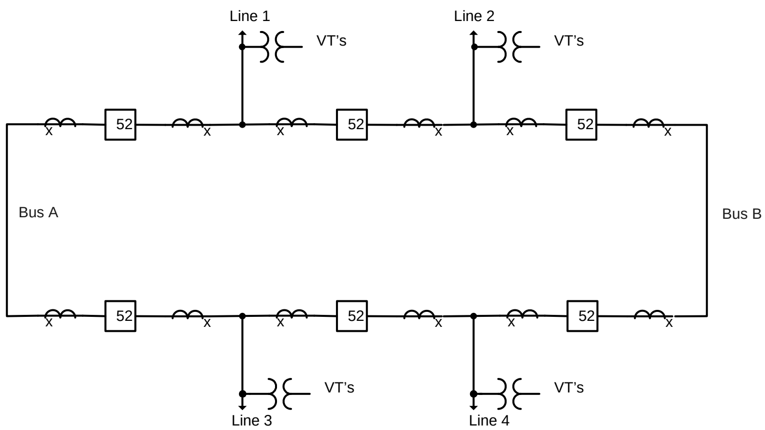
BPA Substation Configurations

- 1 ½ Circuit Breaker Configuration



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Bus Differential Protection

- BPA currently uses the following types of bus differential relays
  - Overcurrent
  - High impedance
  - Static bus differential
  - Microprocessor based bus differential
- Bus differential relays trip a lockout relay LOR
  - The LOR trips all breakers on the bus.
  - The LOR opens all breaker close circuits (close interlock)
  - The LOR is automatically reset in 10 to 15 seconds

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Bus Differential Protection

- Overcurrent Bus Differential Protection
  - Benefits
    - Economical to apply.
      - Breaker currents are summed on a per phase basis.
      - One overcurrent relay element per phase is required.
    - Easy to set
  - Weaknesses
    - All breaker current transformers must be set to the same ratio.
    - Not recommended at substations where ct saturation can occur.
      - All current transformers should be set to the maximum ratio.
    - Older overcurrent relays have an instantaneous trip time that can approach 3 cycles.
      - New relays are required to trip in less than 1.25 cycles (20ms).
    - Problems in ct circuits can cause a false trip.

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Bus Differential Protection

- High Impedance Bus Differential
  - All cts on the bus are summed on a per phase basis. The relay adds a high impedance to the circuit at the summing point. The trip voltage level is set greater than the worst case voltage drop across a fully saturated ct circuit making the relay secure from false operation due to ct saturation.
  - Benefits
    - Economical to apply.
      - Breaker currents are summed on a per phase basis
      - One relay is required per phase
      - Will not false trip if a current transformer saturates during a high magnitude fault.
      - Fast operate time <0.5 cycle
    - Weaknesses
      - All current transformers must be set to the same ratio
      - The current transformers should be operated at the maximum ratio tap.
      - Problems in a ct circuit can cause a false trip.

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Bus Differential Protection

- Static Bus Differential Relay
  - On critical buses BPA uses a static bus differential relay. The relay has the following features.
    - Fast operate time
    - Can tolerate ct saturation
    - Separate ct inputs for each feeder on the bus
      - Each feeder input has ct ratio correction
    - Trip outputs for the breakers as well as for the lockout relay
      - By tripping the breakers directly the overall breaker trip time can be improved by 8 to 16 milliseconds. The lockout relay is still tripped to provide the close interlocking function.
    - Differential alarm that can detect problems in the ct circuits
    - The inadvertent loss current from a loaded feeder will not cause a false trip.
    - Bus imaging. The relay can be automatically reconfigured when the bus configuration is changed.
    - The relay has built in self test logic

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Bus Differential Protection

- Microprocessor Based Bus Differential Protection
  - The performance of the current microprocessor based bus differential relay is similar to the static relay, but the relay much simpler.
    - Fast operate time 10ms
    - Can tolerate ct saturation
    - Separate ct inputs for each feeder on the bus
      - Each feeder input has ct ratio correction
    - Differential alarm that can detect problems in the ct circuits
    - The inadvertent loss current from a loaded feeder will not cause a false trip.
    - Zone selection. The bus is divided into protection zones. The feeders are assigned to these zones. The relay can be automatically reconfigured by switching the feeders into and out of these zones when the bus configuration is changed.
    - The relay has built in self test logic

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Fault Calculations

Fault Studies

- BPA maintains a fault study database of the northwest power grid. The database includes data from most of the utilities in the BPA service area.
  - This database is continually updated as the system changes.
  - Data from the neighboring utilities is also updated regularly.
- The BPA fault study database is maintained and kept up to date in Vancouver, Washington by the System Protection and Control Group (SPC Central)
- In order to maintain consistency all relay settings in the BPA system are set and coordinated using this database
  - Coordination with customers is also done using this database.
  - Fault records from digital fault recorders and line relays are used to check the accuracy of the fault study database.

Fault Studies

- In addition to the normal fault calculations the fault study program has the following additional features
  - Graphical interface
  - View phasors and calculate apparent impedances at the relay location
  - Relay Database
  - Fuse curves and relay timing curves
  - Characteristics for most common distance relays
  - Coordinate relays
  - Simultaneous faults
  - Voltage sag analysis
  - Boundary Equivalent
  - MOV iteration for series capacitors
  - Create fault data file for relay test sets

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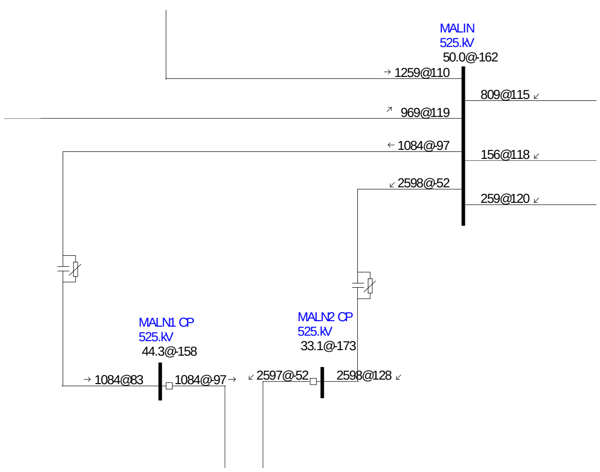
Fault Studies

- Typical Fault Calculation Result



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Fault Studies

- Apparent impedance calculation results.

Fault Description:
4. Interm. Fault on: 0 MALN1 CP 525.kV - 0 RM-MALIN1C 525.kV 1L 1LG 99.50%(99.99%) Type=A
Solution at: 0 MALN1 CP 525.kV end of transmission line 0 MALN1 CP 525.kV - 0 RM-MALIN1C 525.kV 1 L Malin Rd Mt1

Voltages (kV) at this bus:	Currents (A) from this bus:
Va = 220.49@-13	Ia = 1862@-126
Vb = 313.59@-122	Ib = 523@27
Vc = 315.21@123	Ic = 533@20

Reference: System
Apparent impedance to fault (Primary Ohm):
Va/(Ia+3KIo)= 82.1@106.8; Vb/(Ib+3KIo)= 492.1@-53.8; Vc/(Ic+3KIo)= 452.6@-169.8; K=0.79558@-8.2122

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Fault Studies

- The fault study program gives steady state solutions to the faults.
  - The fault study program is good for setting and coordinating relays in most of the system.
  - The fault study program models the operation of series capacitors that are protected by metal oxide varistors MOVs
    - MOVs are non-linear resistors. The resistance varies as the voltage across them increases. The fault study program varies this resistance in steps as the calculated voltage across the series capacitor increases. An iterative process is used to determine the final resistance value. The fault solution is calculated with this resistance in parallel to the series capacitor.
  - Heavily loaded, series compensated lines cannot be accurately modeled by steady state analysis.
    - Transient analysis is needed to verify the settings and performance of protective relays that are applied to these lines.
    - This is mainly a problem on the 500kV system
  -

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Fault Studies

- The fault study program is also used for relay testing. The program creates test files for the relay test sets. These fault study results are played into the relay under test.
- The test sets have GPS clocks with satellite receivers and can be time synchronized for end to end testing. The fault study program is used to create test files for both line terminals.
- BPA uses playback testing for the following
  - Troubleshoot operational problems with protective relays
  - Provide a final check of the settings that are entered into the relay
  - Functionally check the entire protection system including the following
    - Relay trip time
    - Operational logic
    - Transfer trip equipment
    - Reclosing
    - Power circuit breaker trip and close circuits

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Fault Studies

- Electromagnetic Transients Program EMTP
  - BPA uses the Electromagnetic Transients Program EMTP to study the transient response of power system equipment.
    - Breaker switching for example can only be studied using EMTP. The following are examples of studies that require EMTP type analysis.
      - Transient recovery voltage.
      - Transmission line switching
      - Shunt capacitor switching
      - Shunt reactor switching
      - Transformer switching
      - Transmission line switching
      - Faults

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Fault Studies

- BPA tests all new protective relays in the Labs before they are placed in service in the power system.
- Using the EMTP program the portion of the system of interest is modeled in EMTP and a library of fault cases is generated. These faults are created to give worst case operating conditions to the relay under test. In the case of parallel lines relay data files are also generated for the un-faulted parallel line.
  - Some of the problems that are explored are
    - High ground resistance
    - Sub-harmonic oscillations.
    - Heavy loading and load transfer from the faulted line to the un-faulted line.
    - Current reversal on parallel lines.
    - Series compensation
    - Simultaneous faults
    - Cross country faults

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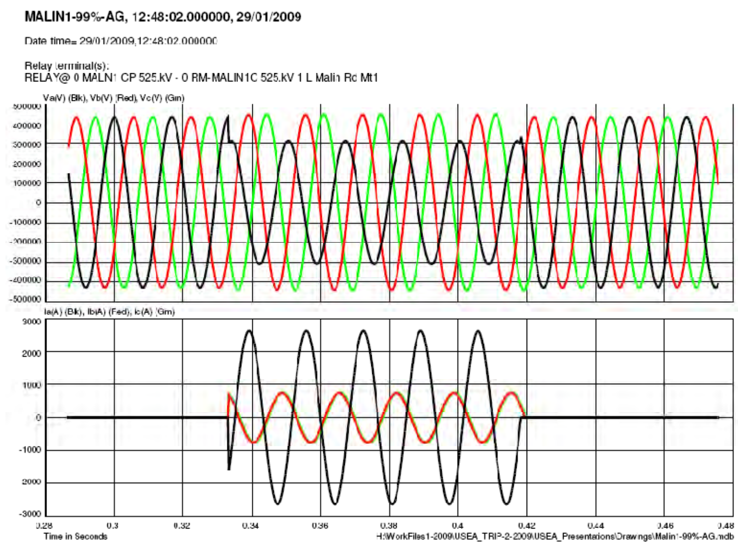
Steady State Test Set Fault File



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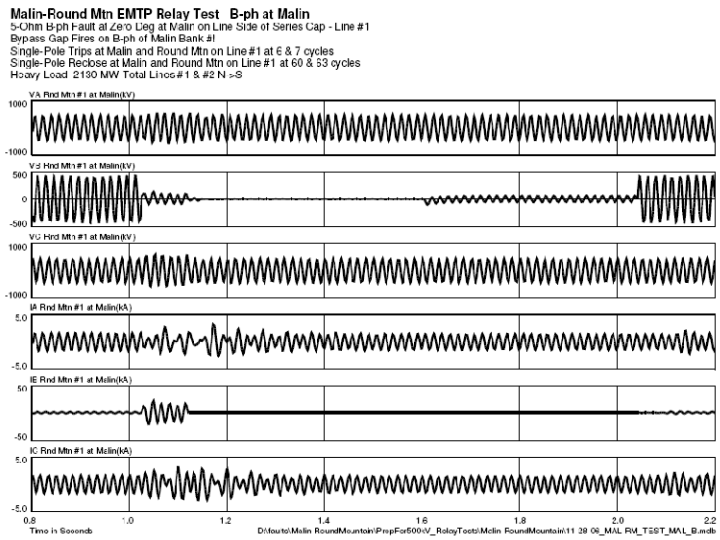
Fault File From EMTP Study



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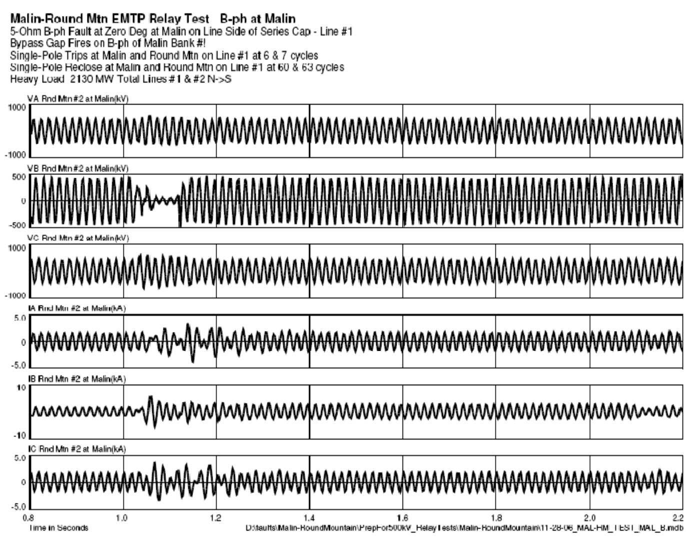
Fault File From EMTP Study



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Comments, Questions?

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Bonneville Power Administration

BPA Transmission Line Protection Overview
2-20-2009

1

115kv Transmission Line Protection

2

BPA 115kV Transmission Line Protection Overview

- Distance (21) Protection. Distance relays measure the impedance to the fault. Typical distance relay functions are:
  - Multiphase fault protection
  - Ground fault protection (21G)
  - Multiple zones of protection
- Directional Ground Over current (67N). The main ground fault protection is provided by ground over current relays.
  - Ground fault protection
    - Time delay (51)
    - Instantaneous (50)
- In most cases, instantaneous tripping at both terminals is not required.
- Redundant protection is required.
  - Electromechanical relays provide backup for each other.
  - Microprocessor based line relays are installed in pairs. Redundant sets of protection is required.
    - No single failure will jeopardize the protection of the line.

3

Typical BPA 115kV Transmission Line Protection

- Distance (21) Protection
- Phase distance protection is always used.
  - Ground distance elements are now becoming available in newer microprocessor based relays, and are being used on a limited basis.
- Distance protection is normally applied in three zones of protection.
  - Zone 1 is set to reach up to 85% of the line impedance.
    - Tripping is instantaneous
  - Zone 2 is set to reach beyond the remote terminal to provide 100% coverage of the line plus provide some remote backup.
    - Tripping is usually delayed from 250ms to 500ms
    - Zone 2 provides some limited backup for the relays at the remote terminal, but it must coordinate with the relays on the adjacent lines at the remote terminal.
    - Zone 2 is set either less than the apparent impedance to the reach setting of the remote zone 1 on the shortest adjacent line at the remote station, or it must be time coordinated with the remote zone 2 relays.
    - On longer lines phase distance relays can pickup due to heavy line load. Zone 2 must not trip due to heavy line loading.

4

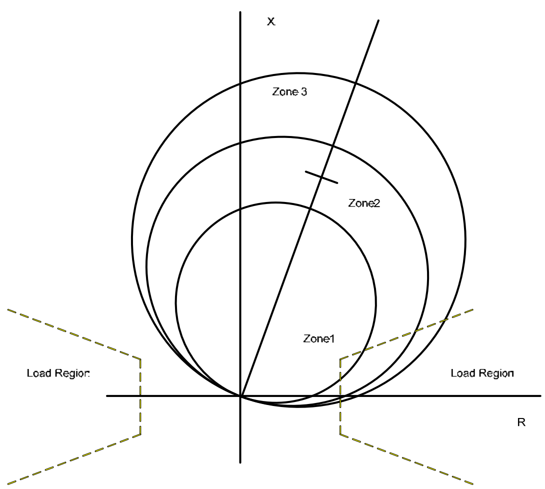
Typical BPA 115kV Transmission Line Protection

- Distance (21) Protection Continued
  - Zone 3 provides a backup for zone 2. It has a longer time delay setting of up to 1 second or more, and can therefore be set more sensitive than Zone 2.
  - Zone 3 on longer lines must not trip under conditions of heavy loading
- Directional Ground Over current Protection
  - The primary ground fault protection on the 115kv system is provided by instantaneous and time delayed directional ground over current relays.
  - The instantaneous element is set to cover as much of the line as possible without over-reaching the remote terminal.
  - The time delayed element has a sensitive setting to detect as much ground resistance as possible.
    - The element has an inverse time characteristic, and is time coordinated with the ground relays on the adjacent lines at the remote terminal.

5

Typical BPA 115kV Transmission Line Protection

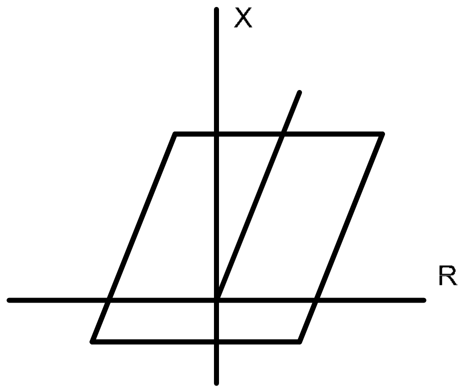
- Typical mho characteristic for a distance relay



6

Typical BPA 115kV Transmission Line Protection

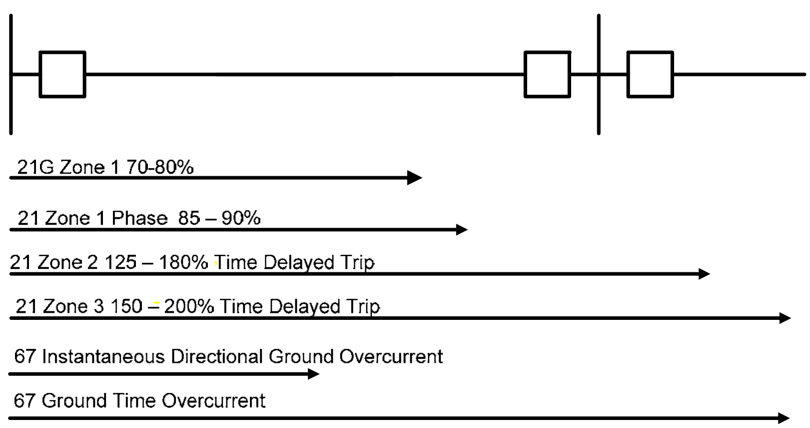
- Typical Quadrilateral characteristic for a distance relay



Quadrilateral Characteristic

7

Typical BPA 115kV Transmission Line Protection



Typical Relay Protection Zones

8

Typical BPA 115kV Transmission Line Protection - Reclosing

- BPA uses 1 reclose cycle on most 115kv lines.
  - A second reclose cycle may be enabled at a customer's point service.
  - A second reclose cycle is needed for line sectionalizing schemes.
- Reclose delay > 35 cycles (583 ms).
  - For faults near the ends of the line the reclose delay must allow for the remote breaker to be cleared by time delayed zone 2, or by the time delayed ground overcurrent relay.
- Synchronization checking is usually not required.
  - BPA usually does not reclose into a line that is terminated by a generator.
  - Static phase angle shifts between the terminals is usually not a problem.
- Hot line checking is used when coordinating reclosers and remote time delayed relays is a problem.
- Recloser reset time 15 seconds.
  - Allows for breaker energy storage systems to recharge in the event of a reclose into a made up fault.

9

230kv Transmission Line Protection

10

Typical BPA 230kV Transmission Line Protection

- Distance (21) Protection
  - Multiphase fault protection
  - Ground fault protection (21G)
  - Multiple zones of protection
- Directional Ground Over current (67N)
  - Ground fault protection
    - Time delay (51)
    - Instantaneous (50) – 2 levels
      - Level 1 trips directly
      - Level 2 Keys the permissive logic in the transfer trip equipment.
- 230kv lines require instantaneous tripping at both terminals. Communications aided tripping (transfer trip) is required.
- Redundant protection is required.
  - Electromechanical relays provide backup for each other.
  - Microprocessor based relays are installed in pairs. Two independent sets of are required.
    - No single failure will jeopardize the protection of the line.

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Typical BPA 230kV Transmission Line Protection

- Distance (21) Protection
- Phase distance protection is always used.
  - Ground distance elements are now becoming available in newer microprocessor based relays, and are being used on a limited basis
- Distance protection is normally applied with three forward zones of protection and one reverse zone.
  - Zone 1 is set to reach up to 85% of the line impedance.
  - Zone 1 provides an instantaneous local trip.
  - Zone 1 transmits a direct trip signal DTT to the remote terminal.
  - Zone 2 is set to reach beyond the remote terminal to provide 100% coverage of the line plus provide some remote backup.
  - Zone 2 provides a time delayed backup trip with typical delays of 250ms to 500ms.

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Typical BPA 230kV Transmission Line Protection

- Zone 2 transmits the permissive signal to the remote terminal.
  - Local tripping will occur if the local terminal also receives a permissive signal from the remote terminal.
- Currently only one set of transfer trip equipment is required per line terminal.
  - Microprocessor based relays have relay to relay communications capability. BPA is starting to enable relay to relay communications for transfer tripping in locations where the communications system has been updated and channels for the relays are available.
- On longer lines phase distance relays can pickup due to heavy line load. Zone 2 must not trip due to heavy line loading.
- Zone 3 is set with a reverse reach in the newer microprocessor based relays where the transfer trip logic is included in the relay logic. Zone 3 is used in the permissive tripping logic to block the echo back signal in the weak end in feed logic, and to set the transient blocking timer during faults on parallel lines.

13

Typical BPA 230kV Transmission Line Protection

- Distance (21) Protection Continued
  - Zone 4 provides a backup for zone 2. It has a longer time delay setting of 1 second or more, and can therefore be set more sensitive than Zone 2.
  - Zone 4 on longer lines must not trip under conditions of heavy loading
- Directional Ground Over current Protection
  - The primary ground fault protection on the 230kv system is provided by instantaneous and time delayed directional ground over current relays.
  - An instantaneous element is set to cover as much of the line as possible without over-reaching the remote terminal.
  - A second instantaneous element has a sensitive setting, and is used in the permissive tripping logic along with the zone 2 element.
  - The time delayed element has a sensitive setting to detect as much ground resistance as possible. When transfer tripping is used, the time delayed element provides backup in the event of loss of communications.
    - The element has an inverse time characteristic, and is time coordinated with the ground relays on the adjacent lines at the remote terminal.

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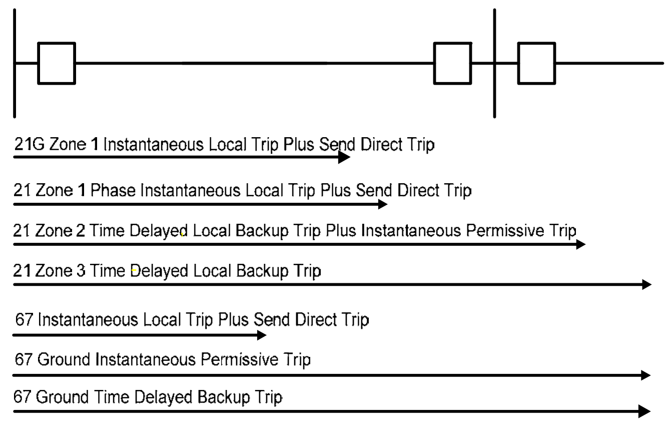
Typical BPA Transmission Line Protection

- Communications Aided Tripping (Transfer Trip).
- Transfer tripping on the BPA 230kv transmission system uses the standard direct under reaching / permissive over reaching transfer trip scheme. These functions back each other up.
  - Under reaching relays such as zone 1 and the instantaneous ground element use the transfer trip direct trip function DTT to send a trip signal to the remote terminal. Backup relays also use the direct trip function to trip the remote terminal when necessary.
  - Permissive over-reaching transfer tripping is an instantaneous, sensitive tripping scheme. Its purpose is to provide instantaneous tripping for 100% of the line. This logic is based on the fact that if the sensitive directional relays (instantaneous zone 2 and instantaneous ground) at both terminals detect a fault in the forward direction, the fault must be on the line. The permissive signal in the transfer trip gear is transmitted when a fault is detected in the forward direction.

Typical BPA Transmission Line Protection

  - When a permissive zone 2 or ground element detects a fault, the permissive logic is keyed. This enables the tripping logic and transmits the permissive signal to the remote terminal. If a permissive signal is received from the remote terminal at the same time, the permissive logic will output a local trip.
- The direct transfer trip function and the permissive transfer trip function operate in parallel and back each other up.
- The backup tripping functions protect the line in the event that communications is lost.
  - Over-reaching distance elements are set with a time delayed backup trip.
  - The line terminal has a time delayed directional ground over current element that is always in service. This element has an inverse time characteristic and is coordinated with the relays at the remote terminal.
  - The zones of protection over lap such that each relay is backed up by another relay.

Typical BPA 230kV Transmission Line Protection



Note: All backup trip functions send direct trip to the remote terminal

Typical Relay Protection Zones With Transfer Trip

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Typical BPA 230kV Transmission Line Protection

- Reclosing
- BPA usually uses 1 reclose cycle on the 230kv system.
- The reclose delay is typically 35 cycles to 60 cycles.
- Synchronization checking is usually not required.
  - BPA does not reclose into a line that is terminated by a generator.
  - Static phase angle shifts between the terminals is usually not a problem.
- Hot line checking and dead line checking are also used to control reclosing. These elements are used to allow one terminal to reclose first and prevent both terminals from reclosing into a made up fault.
- Recloser reset time 15 seconds.
  - The reset delay allows for breaker energy storage systems to recharge in the event of a reclose into a made up fault (O-C-O operation).
- Multi-Phase fault blocking is required for many 230kv line terminals.
  - Reclosing is blocked for multi-phase faults when the possibility that reclosing into a second multi-phase fault will cause system stability problems. This is a problem at the larger substations.

18

Load Encroachment

- Load encroachment occurs when, due to heavy line loading, the load impedance crosses in to the operating characteristic of phase distance relays, tripping the line.
  - Long lines present biggest challenge because the distance relays have longer reach settings.
- Tripping heavily loaded lines can cause cascading outages, and cannot be allowed.
- NERC Loading Criteria is a requirement. The relay must not operate for the following conditions.
  - 150 % of emergency line load rating at -10 deg C
    - BPA maintains a database that lists loading data for all lines and transformers in the system
    - The *Bottleneck Report lists the loading data for the transmission lines.*
  - Use reduced voltage (85 %)
  - 30° Load Angle

Load Encroachment

- Solutions
  - Don’t use the conventional zone 3 direct tripping phase distance element.
  - Some relays allow the circular mho characteristic to be modified to a lens characteristic to reduce the resistive reach.
  - Reduce the blinder settings in relays that have a quadrilateral characteristic.
  - Tilt mho characteristic angle toward 90°.
  - Most modern line relays have built in load encroachment logic.
  - Request special NERC exception.
    - NERC Standard PRC-023-1

General BPA Transmission Line Protection Practice

- Other Line Protection Schemes
  - Current Differential Relays
    - BPA uses current differential relays on shorter lines. Most of these relays communicate with each other by direct fiber optic cables.
    - As the communications system is being updated to digital, the protective relays have greater access to needed channel bandwidth. Digital channel banks provide synchronous 64kbps channels for the relays. This will allow for more widespread use of current differential relays in the future.
  - Charge Comparison Relays
    - Charge comparison relays are similar to current differential relays. BPA has a number of these relays in service. They are also used on shorter lines, and are mainly communicating over direct fiber.
  - Current differential protection is communications dependent. Current differential relays are never applied without backup. BPA prefers to backup current differential relays with distance relays.

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500kv Transmission Line Protection

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500kV Transmission Line Protection Overview

- The BPA 500kv Grid
  - Power is transferred over long distances.
  - Many of the long lines are heavily loaded.
  - Some long lines are on double circuit towers.
  - The grid has intertie lines to California, Montana, and Canada.
  - Many of the longer lines are series compensated.
  - Most of the lines are operated single pole.
    - RAS, series compensation, and single pole switching are used to increase loading on the 500kv system.
  - Redundant relay sets are used on all line terminals.
    - Each relay set has its own communications equipment (transfer trip equipment) that communicates over alternate paths.

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500kV Transmission Line Protection

- Protective relay requirements.
- Two redundant protection systems per line terminal.
  - Different manufacturers or operating principles for each set.
- Operating time of the instantaneous elements <1.5 cycles.
  - Static traveling wave relays operating times <0.5 cycles.
  - Modern microprocessor based relays typically have operation times of <0.75 cycles for the instantaneous elements.
- Single pole tripping for ground faults.
- Operate on series compensated lines.
- Each set of relays has its own communications equipment (transfer trip) operating on alternate communications paths.
  - End to end transfer trip times are less than 1 cycle for the primary communications path and less than 1.25 cycles for the alternate path.

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500kV Transmission Line Protection

- The relays must be able to operate with the currently available communications equipment.
  - The BPA communications system is currently being upgraded from the older analog microwave radios to newer digital communications.
    - Older analog systems allocate one 4khz voice grade channel per relay set for transfer tripping purposes. The transfer trip equipment for these channels provides either two or four discreet transfer tripping functions.
      - Most of the protective relays in the BPA system are using this older audio transfer trip equipment.
      - Distance relays and traveling wave relays operate well with this older transfer trip equipment.
    - With the newer digital radios and fiber optic SONET rings, one 64kbps synchronous communications channel is now available for each set of line relays.
      - BPA is now increasing its use of direct relay to relay communications for transfer tripping instead of using the additional external equipment that has been required in the past.

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500kV Transmission Line Protection

- With the availability of synchronous communications channels, BPA plans to incorporate current differential protection in the 500kv system in the future.
- Transfer trip logic for 500kv relays.
  - The 500kv line relays use instantaneous under-reaching relays and permissive overreaching relays for the primary high speed tripping functions.
  - The permissive tripping scheme is similar to the 230kv scheme.
    - When a permissive relay detects a fault in the forward direction it keys the permissive tripping logic, which enables the permissive tripping logic and transmits the permissive signal to the remote terminal.
    - Tripping occurs when the local permissive relay operates, and at the same time, a permissive signal is received from the remote terminal.

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500kV Transmission Line Protection

- Some relays use phase segregated permissive tripping. Each phase has a permissive signal and separate permissive tripping logic. This is mainly used for double circuit lines where one phase on one circuit can fault to another phase on the other circuit (cross country fault). Phase segregated permissive tripping assures that the correct phase is tripped on each circuit.
- The direct transfer trip function sends a backup three pole trip to the remote terminal. All protection backup trips send a three pole trip to the remote terminal.
  - Some relays also have single pole direct tripping enabled. This scheme transmits a single pole trip to the remote terminal. Any time a terminal trips single pole, the other terminal must also trip single pole. Single pole direct tripping assures that this will occur.

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500kV Transmission Line Protection Overview

- The main types of protective relays that are used on the on the BPA 500kv grid are:
  - Under impedance relays (distance relays) are the standard type of protection for 500kv lines in the BPA system.
  - Static traveling wave relays were installed in large numbers on the BPA system in the 1990s.
  - The line relays are all backed up by a sensitive time delayed ground over current relay. This relay trips three pole with a long delay. It gives one final level of protection for high resistance ground faults.
  - Line differential relays are currently used on short lines where direct fiber optic cables are available.
    - As digital communications become available at more substations, BPA plans to use current differential protection on longer lines. These relays will always operate in parallel with distance elements.

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500kV Transmission Line Protection Overview

- Primary Tripping Functions – Impedance relays and Traveling wave relays.
  - Instantaneous under reaching, communications independent single phase and multi-phase tripping
  - Instantaneous over reaching, communications dependent single phase and multi-phase permissive tripping.
    - BPA normally uses permissive tripping logic
- Backup Tripping
  - A backup trip occurs for any of the following operations:
    - Over reaching time delayed backup trip
    - Evolving fault during a single pole trip operation.
    - Close onto fault. Also referred to as Switch onto fault logic.
    - Reclose into a fault.
    - Any fault that occurs after a successful reclose, but before the recloser has reset (15 seconds)

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500kV Transmission Line Protection Overview

- Reclose failure. The circuit breakers are only allowed to remain in a single pole open condition for a limited time, usually less than 2 seconds. If the open pole fails to close, a three pole trip is issued.
- Receive a backup direct three pole trip from the remote terminal
- Trip from the backup directional ground over current relay

- A backup trip does the following:
  - Trip the breakers three pole
  - Blocks reclosing
  - Transmits a backup direct trip to the remote terminal
  - Keys line loss logic LLL signals to the RAS controllers

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500kV Transmission Line Protection Overview

- Traveling Wave Relays
  - Traveling wave relays were installed on the BPA system in the 1980s and 1990s.
  - Advantages of traveling wave relays
    - Fast operating time <0.5 cycle
    - Operate with minimum communications equipment requirements
      - The relays operate in the permissive tripping mode and need only one permissive communication signal.
    - Not affected by series capacitors
    - Not affected by sub harmonic oscillations and system swings.
    - Do not measure load. Load encroachment is not a problem.
  - Disadvantages of traveling wave relays.
    - Traveling wave relays operate on the first ¼ cycle of a fault. The voltage and current changes must occur within a narrow time window or the relay will not detect the fault.

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500kV Transmission Line Protection Overview

- Traveling wave relays do not operate on the steady state fundamental system frequency component of the voltage and current. They cannot provide time delayed backup tripping.
- The wave detectors may not operate when closing into a dead line if the line faults on energization. An impedance based switch onto fault relay is included to cover this possibility.

- Traveling wave relays must have back up. BPA backs up all traveling wave relays with single pole distance relays.
- Traveling wave relays have three levels of primary protection.
  - The relays have an under reaching, communications independent wave detector for close in faults.
  - The relays also have two levels of sensitive permissive tripping elements.
- The relays also have two backup functions.
  - Switch onto fault logic is enabled on a dead line. This logic enables a backup distance relay.
  - Weak end in feed logic echos a received permissive signal back to the sending terminal if it receives the signal, but does not detect either a forward or a reverse fault. This allows the remote terminal to trip. Additionally the weak terminal will trip locally on undervoltage.

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500kV Transmission Line Protection Overview

- Impedance Relays (Distance Relays)
- Impedance relays are the main protection relays on the BPA system including nearly all 500kv lines.
- The 500kv impedance protective relays have the following requirements
  - Single pole operation
  - High speed instantaneous tripping
  - At least three forward zones of protection and one reverse zone of protection.
  - Must operate on series compensated lines.
  - Weak end in feed logic.
  - The relays have switch onto fault logic for closing into dead lines.

33

500kV Transmission Line Protection Overview

- Impedance relays have three primary zones of protection and one or two backup zones.
  - Zone 1 trips single pole for ground faults and three pole for multi-phase faults.
    - Zone 1 is set normally 70% to 85% of the line.
      - Tripping is either three pole or single pole depending on the fault.
      - Tripping is instantaneous.
  - Zone 2 is a permissive tripping element.
    - Zone 2 is set to over reach the remote terminal for all faults(Z2>125%*Zline).
      - When zone 2 picks up the permissive logic is enabled, and a permissive signal is sent to the remote terminal. If a permissive signal is received from the remote terminal at the same time, a local permissive trip will occur.
      - Tripping is either single pole or three pole depending on the fault.
      - Tripping is instantaneous.

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500kV Transmission Line Protection Overview

- Zone 3 is set reverse.
  - Zone 3 does not trip.
  - Zone 3 blocks the permissive echo back logic for reverse faults.
  - For fault operations on parallel lines the permissive tripping logic can mis-operate if momentary current reversals occur during the fault clearing operation. Zone 3 detects these reversals and sets the transient blocking timer in the permissive current reversal logic. The timer blocks the permissive logic long enough for the fault on the parallel line to clear at both terminals.
- Zone 4 is a backup tripping element.
  - Zone 4 is set to over reach the remote terminal for all faults.
  - Tripping is time delayed. The typical trip time setting is 250ms.
  - Tripping is three pole.
- 500kv relay settings must meet the NERC requirements for load encroachment.

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500kV Transmission Line Protection Overview

- Line Differential Relays (Current Differential)
  - Current differential relays have the following advantages.
    - Not affected by heavy load and load transfers during single pole switching.
    - Not affected by out of step events
    - Not affected by series capacitors
    - Do not respond to sub-harmonic oscillations
    - Sensitive settings can detect high resistance ground faults
  - Current differential relays have the following disadvantages.
    - Communications dependent
    - Line charging current must be accounted for. This is mainly a problem on longer lines.
    - Tapped loads create differential currents

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500kV Transmission Line Protection Overview

- Reclosing
  - Reclosing is only allowed for single line to ground faults.
  - Reclose delays vary from 0.5 to 1 second.
    - For some relay schemes this delay is increased up to 1.5 seconds.
  - For transmission lines synch checking is normally not used. System Operations does not want a sync check relay preventing them from closing breakers on critical transmission lines.
  - Recloser dead times are staggered such that one terminal will reclose first to test the line.
    - A typical reclosing sequence is to reclose one terminal first to test the line. If that terminal remains closed the second terminal will reclose. If the first terminal recloses into a fault, a backup three pole trip will be sent to the second terminal to block its recloser. An additional delay of 10 to 15 cycles at the second terminal is enough margin for the first terminal to reclose into a fault and send a backup trip to the second terminal and block its recloser.
  - A line loss logic signal is sent to the RAS controllers when reclosing is not successful.

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Microprocessor based relays

- All protective relays that BPA currently installs in its transmission system are microprocessor based relays. In addition to the protection functions these relays have many additional features.
  - Relay to relay communications
  - GPS clock
  - Event reporting
  - Oscillography
  - Programmable operating logic
  - Instrumentation
  - Wider setting range. Current transformers can normally be operated on their maximum ratios. The burden of the current inputs is also very low.
  - Control and automation
  - Reclosing, synchronizing, hot line and dead line checking
  - Breaker failure protection. BPA currently uses separate breaker failure protection.

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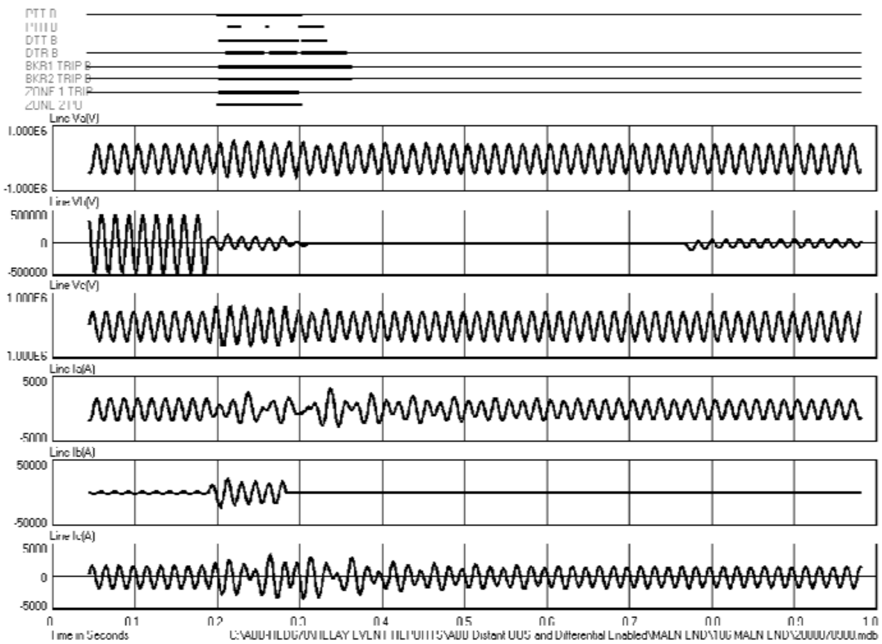
Event Report from a microprocessor based line relay



Event list

Number	Name	Status	Time
6	L3D PU A	On	6/3/2008 9:48:04.575 AM
9	BLK2NDHARM A	On	6/3/2008 9:48:04.575 AM
12	BLK5THHARM A	On	6/3/2008 9:48:04.575 AM
30	ZONE 4 PU	On	6/3/2008 9:48:04.576 AM
25	ZONE1 TRIP	On	6/3/2008 9:48:04.579 AM
28	ZONE 2 PU	On	6/3/2008 9:48:04.579 AM
31	BKR1 TRIP A	On	6/3/2008 9:48:04.579 AM
34	BKR2 TRIP A	On	6/3/2008 9:48:04.579 AM
87	CS_A	On	6/3/2008 9:48:04.579 AM
12	BLK5THHARM A	Off	6/3/2008 9:48:04.580 AM
5	L3D TRP ENHAN	On	6/3/2008 9:48:04.585 AM
17	LDL DIFF TR A	On	6/3/2008 9:48:04.586 AM
47	AR01 READY	Off	6/3/2008 9:48:04.588 AM
48	AR02 READY	Off	6/3/2008 9:48:04.588 AM
91	AR01 ACTIVE	On	6/3/2008 9:48:04.588 AM
92	AR02 ACTIVE	On	6/3/2008 9:48:04.588 AM
20	LDL TR REMOTE	On	6/3/2008 9:48:04.596 AM
3	L3D TRP RESTR	On	6/3/2008 9:48:04.600 AM
9	BLK2NDHARM A	Off	6/3/2008 9:48:04.600 AM
5	L3D TRP ENHAN	Off	6/3/2008 9:48:04.600 AM
4	L3D TRP UNRES	On	6/3/2008 9:48:04.600 AM
4	L3D TRP UNRES	Off	6/3/2008 9:48:04.605 AM
73	BKR1 52b-A	On	6/3/2008 9:48:04.623 AM
76	BKR2 52b-A	On	6/3/2008 9:48:04.626 AM

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Breaker Failure Protection – 115kv and 230kv Breakers

- BPA uses current supervised breaker failure protection.
- Breaker failure protection is initiated by a trip signal from the protective relays.
  - The breaker failure timer is started when the over current fault detector is picked up and a protective relay outputs a trip to the circuit breaker.
    - If the fault clears normally the breaker opens and the over current fault detector drops out before the delay on the BFR timer expires.
  - The BFR timer is normally set to 8 cycles (133 ms) for 2 and 3 cycle circuit breakers. The delay may be extended for slower breakers.
  - The breaker failure relay trips a lockout relay.
    - The lockout relay trips all adjacent breakers to clear the fault.
    - The lockout relay also has close interlocking in the close control circuits of the breakers. Close interlocking blocks close commands to the breakers and drives all of the reclosers to lockout.
  - The Breaker failure relay also outputs an instantaneous retrip to the second trip coil.

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Breaker Failure Protection – 500kv Breakers

- Breaker Failure Protection is required on all 500kv breakers.
- At the present time redundant breaker failure relays are not required.
- The protection elements operate on a per phase basis for operation with single pole tripping logic.
- The protection functions are initiated by protection trip operations, control trip operations, and control close operations.
- The relay provides a single pole re-trip to the backup trip coils
- The protection functions include:
    - Standard breaker failure protection. The logic requires a breaker trip command plus an over current fault detector to start the timer. The delay is normally set to 8 cycles.
    - The line charging current mode uses a more sensitive over current fault detector and trips with a longer delay.
      - This function was added to detect opening resistor and contact failures when a breaker de-energizes a line.

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Breaker Failure Protection – 500kv Breakers

- Flash over of an open breaker
- Open and close resistor failure – not used
- Current unbalance on close – failure of a pole to close

- The breaker failure protection elements trip line and bus lockout relays. The lockout relays trip all breakers that are sources to the failed breaker. The lockout relays also send direct trip signals to the remote terminals of affected lines.
- The BFR logic supervises the reset of the lockout relays. The lockout relays are not allowed to reset until the failed breaker is isolated from the power system.
- The LOR trip and reset logic in the BFR isolates the failed breaker by automatically opening the isolation disconnects (auto isolation) The station can then be restored remotely by scada.

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Breaker Failure Protection – 500kv Breakers

- Newer versions of the 500kv breaker failure relays have additional open and close control logic. This includes
  - Synch checking
  - Hot line and dead line checking
  - Point on wave closing
    - BPA is beginning to use point on wave closing on transmission lines to reduce switching surges and on power transformers to reduce inrush.
  - Point on wave opening
    - Re-ignitions and re-strikes are a problem with the newer SF6 breakers. BPA is starting to use point on wave opening on circuit breakers to reduce re-strikes and re-ignitions.
  - Circuit breakers that are dedicated to shunt capacitor and shunt reactors are purchased open and close controllers.

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Questions, Comments, Discussions

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Bonneville Power Administration

Single Pole Switching, Series Compensation, Communications

2-20-2009

1

Single Pole Switching

- Grid power transfer capacity can be increased by the following methods
  - Remedial Action Schemes
  - Single pole switching
  - Add series capacitors to long lines
  - Construct more transmission lines
    - Adding more transmission lines is very costly and it is getting increasingly difficult to get transmission right of ways.
      - Adding transmission lines is done only when the other options are no longer adequate.

2

Single Pole Switching

- Single pole switching helps increase the load transfer capability of the 500kv grid
    - A typical single line to ground fault clearing operation opens the faulted phase only and does not simultaneously interrupt load in the two un-faulted phases.

- Most faults on the 500kv grid are single line to ground faults and can be cleared with single pole switching.
- BPA has been using single pole switching on the 500kv transmission system since the 1970s.
    - Currently nearly all 500kv transmission lines in the BPA system are operating with single pole switching.
        - The exceptions are lines to generation stations and short, transformer terminated lines.

3

Single Pole Switching – 500kv Breakers

- 500kv breaker requirements
    - Single pole operating mechanisms
    - Two trip coils per phase (Redundant trip coils)
    - Dead Tank Breaker
        - Lower profile and less prone to damage during earthquakes
    - Explosion proof
        - Increase personnel safety
        - Reduce collateral damage from breaker internal faults
    - 2 cycle trip time rating
        - Contact parting begins in < 20milliseconds and current is interrupted at the next current zero.

4

Single Pole Switching – 500kv Breakers

- 500kv breaker requirements Continued
  - Resistorless breakers
    - In BPA a high percentage of failures of older air blast breakers were failures of the closing resistors. BPA has since eliminated closing resistors on all newer breakers except in a few cases where they are required. EMTP switching studies are used to evaluate breaker switching performance.
  - Staggered pole closing and Single pole closing
  - Breakers that switch only shunt reactors and shunt capacitors are also included with Point on Wave open and close controllers

5

Single Pole Switching – 500kv Breakers

- Newer breakers in the BPA system are SF6 breakers
  - SF6 breakers have a problem interrupting high magnitude faults when the rate of rise of the transient recovery voltage TRV is too steep.
  - TRV capacitors are connected externally across the breaker bushings to reduce the rate of rise of TRV
- BPA engineers use the EMTP transient analysis software to study breaker switching performance at the various locations in the power system prior installing the breakers.

6

Single Pole Switching – Breaker Switching

- Switching surges occur during line energization when a circuit breaker is closed into a dead line
- BPA controls switching surges on lines with resistorless breakers by using staggered pole closing and metal oxide surge arrestors
  - Staggered pole logic closes one pole first, then in 1 to 1.25 cycles (1.66 to 20 ms) the second pole is closed, and the third pole is closed 1 to 1.25 cycles after the second pole.
    - This separates the switching transients between phases in time such that the inter-phase coupling of the transients cannot add to each other and increase the transient overvoltage along the line.
  - 1.7 pu metal oxide surge arrestors are installed at the line terminals. The surge arrestors clip the switching transients at the open end of a line when the line is energized by a resistorless, SF6 breaker at the remote terminal.

7

Single Pole Switching - Breaker Switching

- Switching Surges and transients Continued
  - BPA is in the early stages of implementing point on wave closing and point on wave opening on 500kv transmission line breakers.
    - Point on wave closing reduces switching transients.
    - The current scheme uses staggered pole closing, but also closes the individual poles at voltage zeros since an open ended transmission line is mainly capacitive.
      - In the future trapped charge detection will be included in these schemes.
    - Point on wave opening reduces contact re-strikes and re-ignitions
      - An open command is issued to each pole such that contact parting begins just after a current zero (20 deg to 40 deg). This gives the maximum contact separation and greatest dielectric strength at the next current zero increasing the probability of a successful interruption of current.

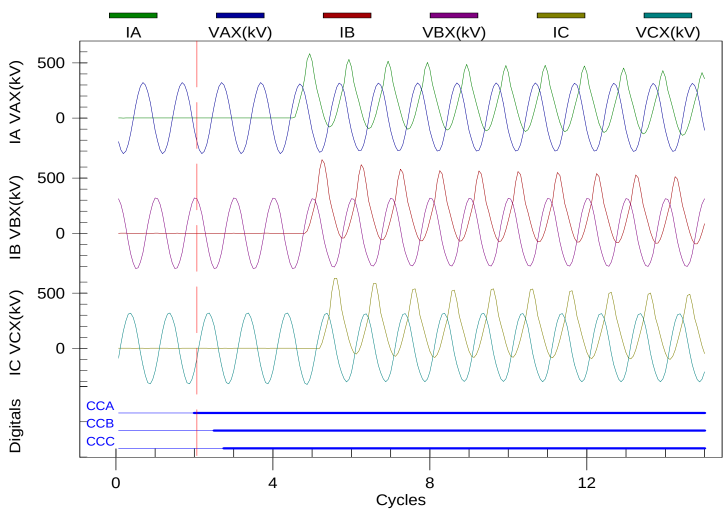
8

Single Pole Switching - Breaker Switching

- Point On Wave Switching Continued
  - Shunt Capacitors
    - BPA uses point on wave closing to reduce switching transients on 500kv shunt capacitors
      - Poles are closed at voltage zeros
      - Current limiting reactors are also used when necessary
  - Shunt Reactors
    - POW closing eliminates current dc offset.
      - Poles are closed at voltage peaks
    - POW opening minimizes contact re-ignitions and re-strikes.
  - Power Transformers
    - POW Closing reduces inrush on energization
      - Timing settings are determined by EMTP studies
    - POW opening minimizes contact re-ignitions and re-strikes

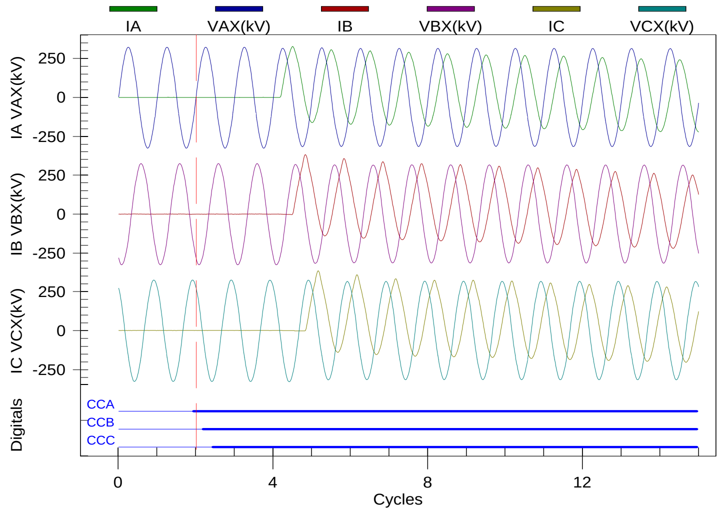
9

Single Pole Switching - No POW Close



10

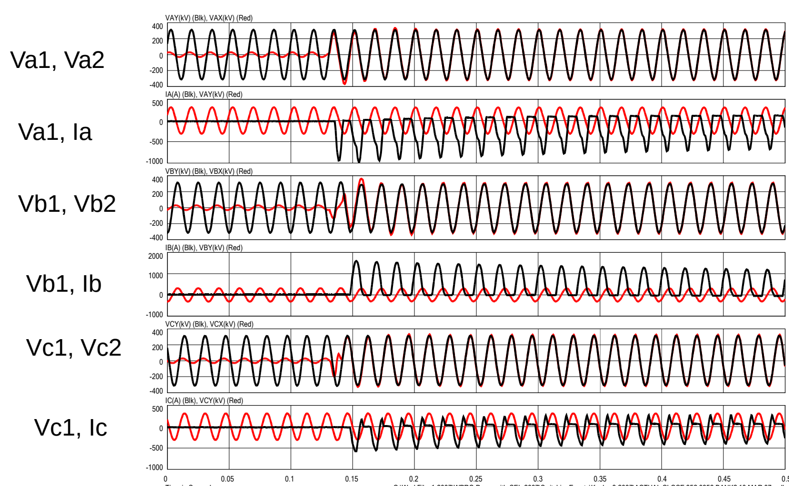
Single Pole Switching - Close With POW



11

Single Pole Switching – Energize 500kv Transformer

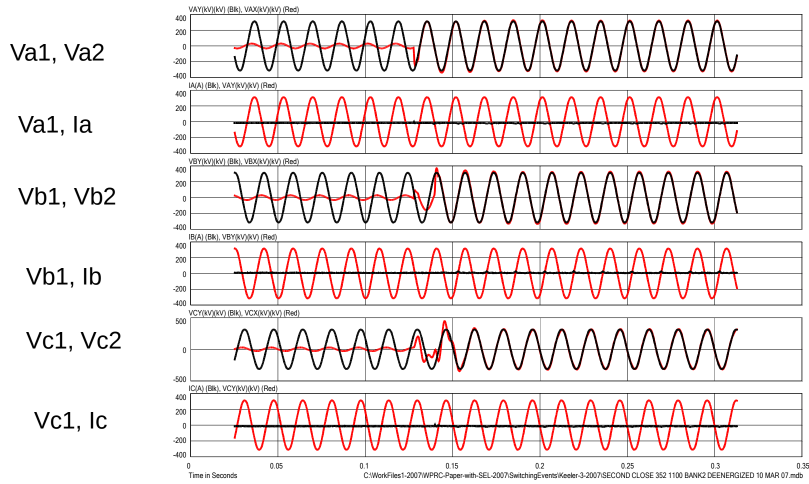
Close with inrush



12

Single Pole Switching – Energization with POW Closing

Close with no inrush



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Single Pole Switching

- Reclosing
  - Reclosing is not allowed for multi-phase faults.
  - Backup protection trip operations such as reclosing into a fault, failure to reclose, and evolving faults block reclosing.
  - Only one reclose attempt is allowed
  - Typical reclosing delays are 0.5 to 1 second. The setting must allow enough time for the secondary arc to extinguish.
  - Reclose delays are normally staggered between terminals such that in the event of a reclose into a fault only the first terminal will reclose. The second terminal will be blocked by a backup trip signal from the first terminal before it can reclose.
  - Sync checking and dead line checking are normally not needed

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Single Pole Switching – The Secondary Arc

- During a single pole switching operation of a transmission line, the faulted phase is de-energized and the two un-faulted phases are energized during the reclose interval.
- Capacitive coupling to the two un-faulted phases, or to an adjacent line on double circuit towers can delay the de-ionization of the fault arc path by supplying capacitive current to the de-energized phase. This current feeds the secondary arc.
  - As lines get longer the coupled current in the secondary arc gets larger and the arc de-ionization time increases. At some point the current in the secondary arc will be large enough and the secondary arc will not extinguish. Typical lines in the BPA system that are longer than about 70 miles (113km) (less for some tower configurations) have enough coupled current to sustain the secondary arc and it will not extinguish. Reclosing will be unsuccessful.

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Single Pole Switching – The Secondary Arc

- Reclosing can be delayed for up to 1 second in order to allow the secondary arc to extinguish.
- When the line length and line configuration are such that the secondary arc cannot be reliably extinguished during the reclose dead time BPA must use other means to extinguish the secondary arc. BPA has three additional schemes that are used to extinguish the secondary arc prior to reclosing.
  - 1. Four Reactor Scheme
  - 2. High-speed Ground Switches
  - 3. Hybrid Single Pole Tripping

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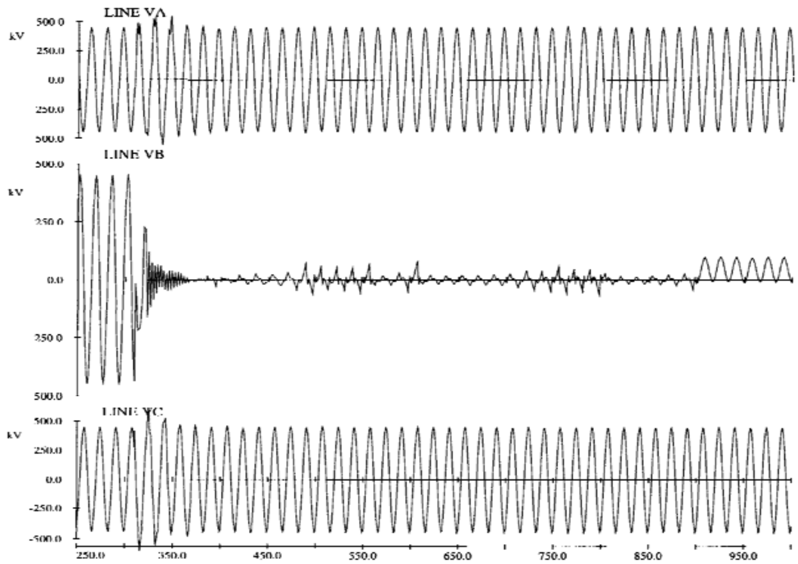
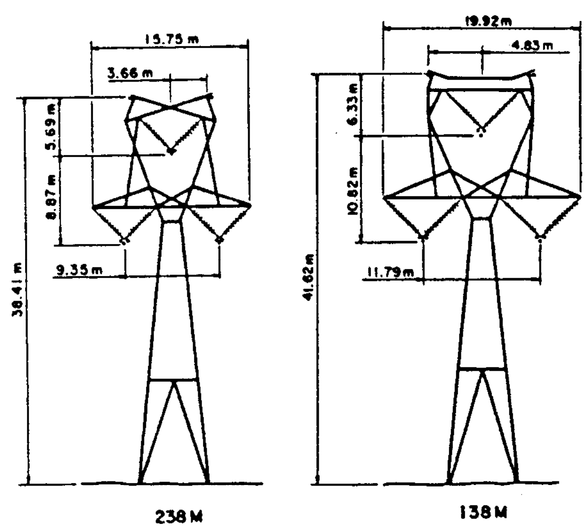
Natural Secondary Arc Extinction Field Test



17

Reduced Insulation vs Standard Towers



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Standard Single-Circuit Tower

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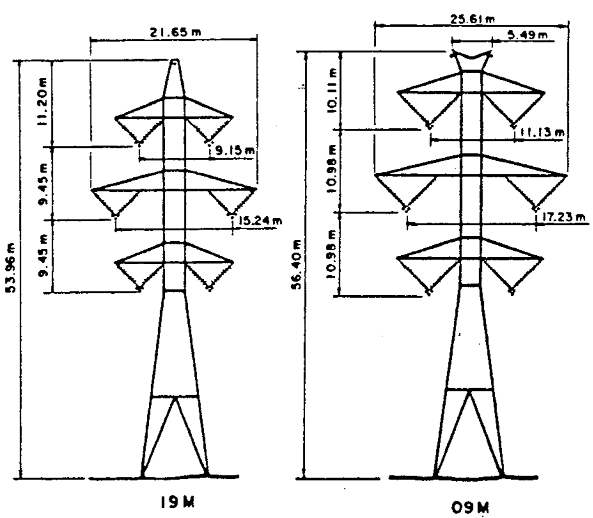
Reduced Insulation vs Standard Towers



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Reduced Insulation Double-Circuit Tower

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Single Pole Switching – The Secondary Arc

- Four Reactor Scheme
  - Shunt reactors are installed at one or both line terminals depending on the line.
  - A reactor is installed in the neutral bus at the ground point.
    - The neutral reactor is sized such that inductive current from the reactors on the two un-faulted phases summed through the neutral reactor cancels out the capacitive current in the arc path.
  - On some lines, particularly series compensated lines, the shunt reactors may need to be switched out of service for voltage control.
    - For these lines a fast reactor insert scheme is included in the reclose logic. The protective relays trip the faulted phase, initiate the reclose sequence, and insert the line reactor to extinguish the secondary arc prior to reclosing.

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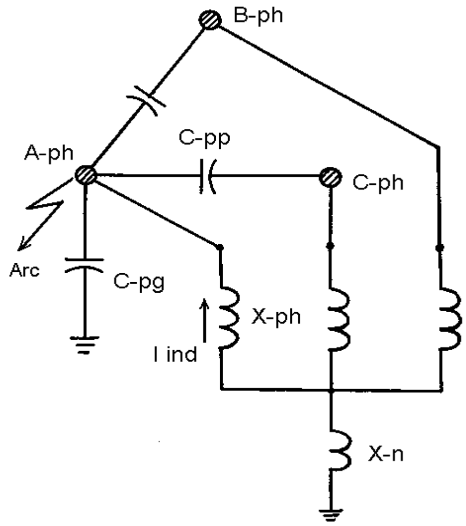
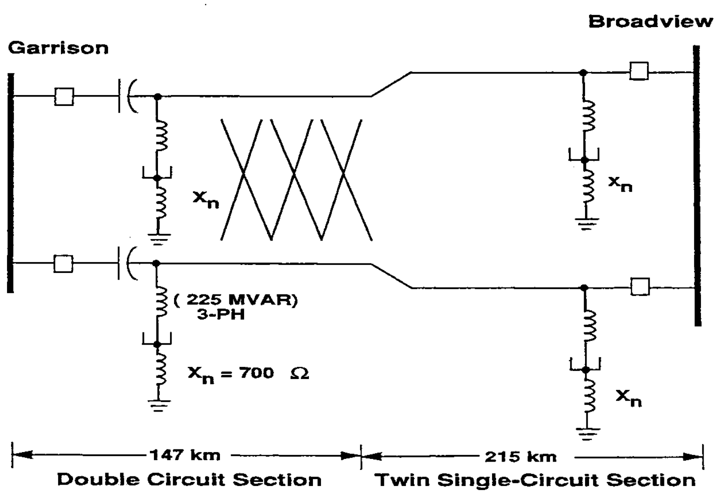
Single Pole Switching – The Secondary Arc

Four Reactor Scheme
Neutral Reactor

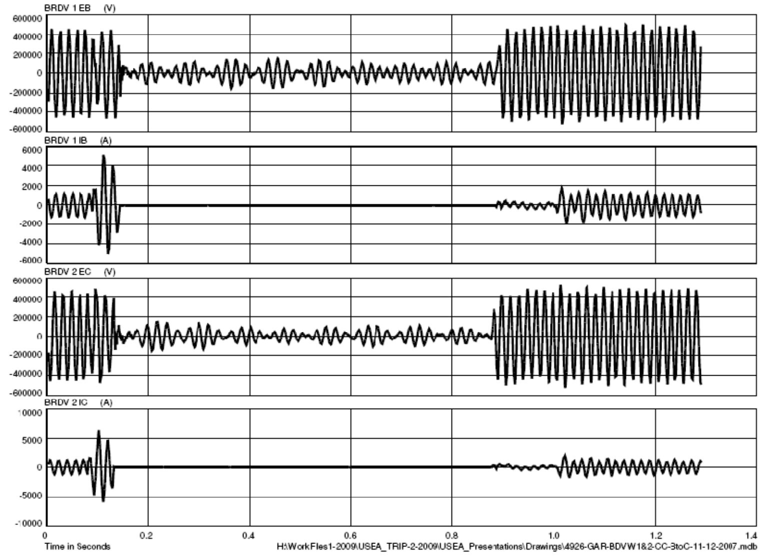
The impedance is sized such that the Inductive Current into Phase A Cancels Out Capacitive Current From Phases B & C



Four Reactor Scheme



Four Reactor Scheme – Cross Country B to C



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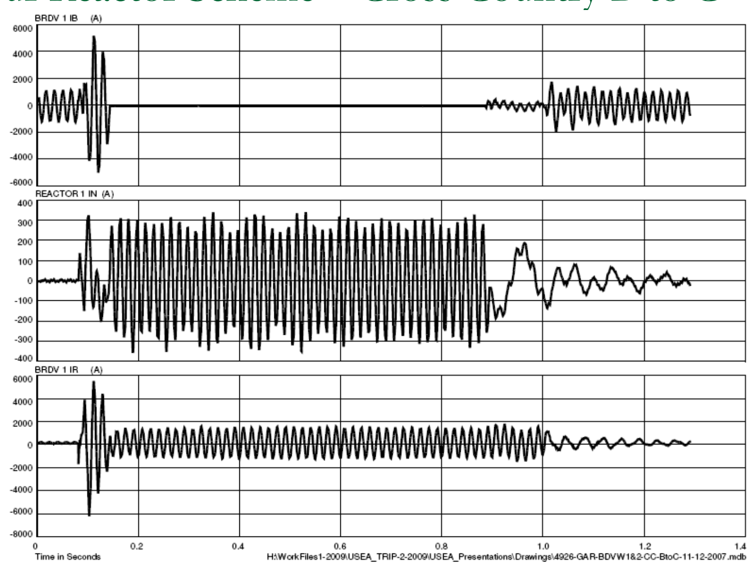
Four Reactor Scheme – Cross Country B to C



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Single Pole Switching – The Secondary Arc

- High Speed Ground Switches
  - In some cases when the shunt reactors are used for voltage control they are located on the bus rather than on the line.
  - High Speed ground switches are installed at the line terminals to extinguish the secondary arc.
    - The high speed ground switches at both terminals are closed about 7 cycles (approx. 120ms) after the faulted phase is open and verified open.
    - The ground switches remain closed for about 15 cycles (250ms) to extinguish the secondary arc and are opened.
    - After the ground switches are verified open, the line can be reclosed.
      - Load on the line is restored in about 1 second

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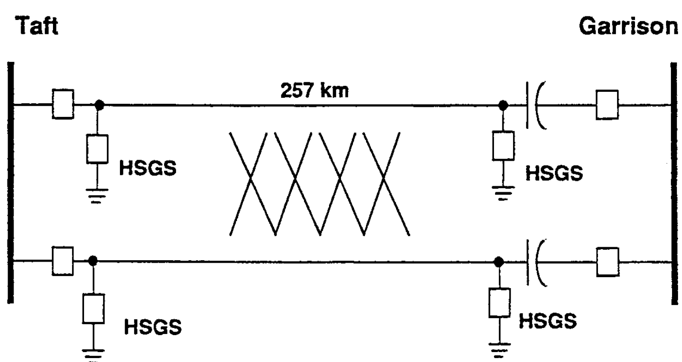
HSGS on Long, Double-Circuit Line

Taft – In GIS Substation, HSGS is Fast GIS Disconnect
Garrison – Air Sub, HSGS is Free-Standing Breaker



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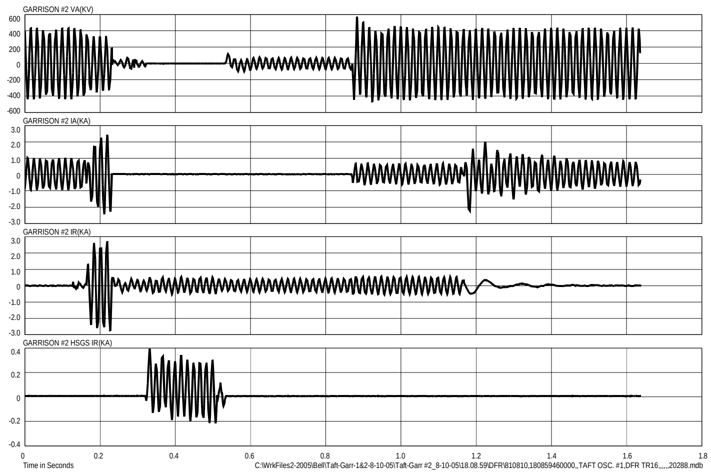
High Speed Ground Switch – A to Ground – Forest Fire



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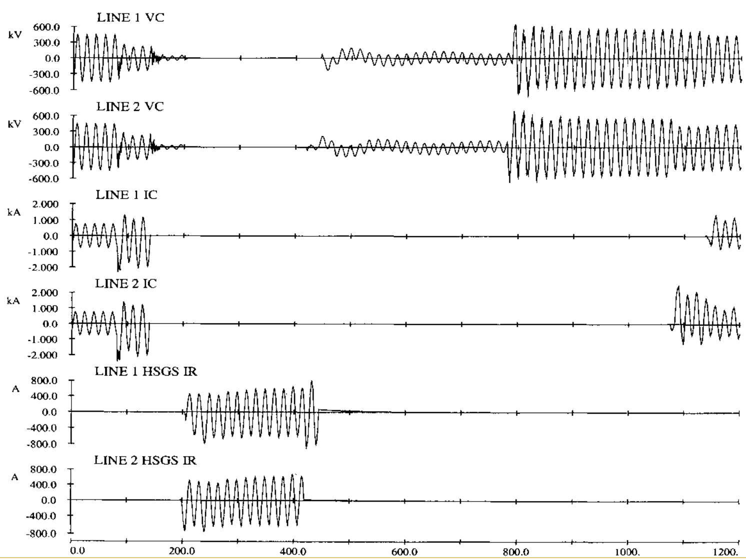
Garrison-Taft Simultaneous Faults



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New 500 kV HSGS

345 kV Breaker
With One
500 kV Bushing

Single Pole Switching – The Secondary Arc

- Hybrid Single Pole Tripping
  - Four reactor schemes and high speed ground switches are used on long intertie lines, but are not very practical for the longer lines in the main grid.
  - The transmission lines in the main grid are more closely interconnected so the main grid can tolerate a three pole trip of a heavily loaded line as long as the three pole trip occurs after the single line to ground fault is cleared from the system, and the system has stabilized.
  - System studies determined that the optimal time to open the breaker three pole is 50 cycles (833ms) after the phase to ground fault has cleared.

Single Pole Switching – The Secondary Arc

- Hybrid Single Pole Tripping Sequence
  - 1. Single line to ground fault
  - 2. 3 to 3.5 cycles (50 to 58 ms) open the faulted phase to clear the fault
  - 3. 50 cycles (833 ms) trip the line three pole
  - 4. Add 20 cycles dead time after the three pole trip and reclose the first terminal. 50cycles +20cycles = 1.2 seconds
  - 5. Add 12 to 15 cycles and reclose the second terminal. 1.4 seconds
- Hybrid single pole tripping is the method of that is currently in use by BPA to extinguish the secondary arc on the longer lines in the 500kv main grid.

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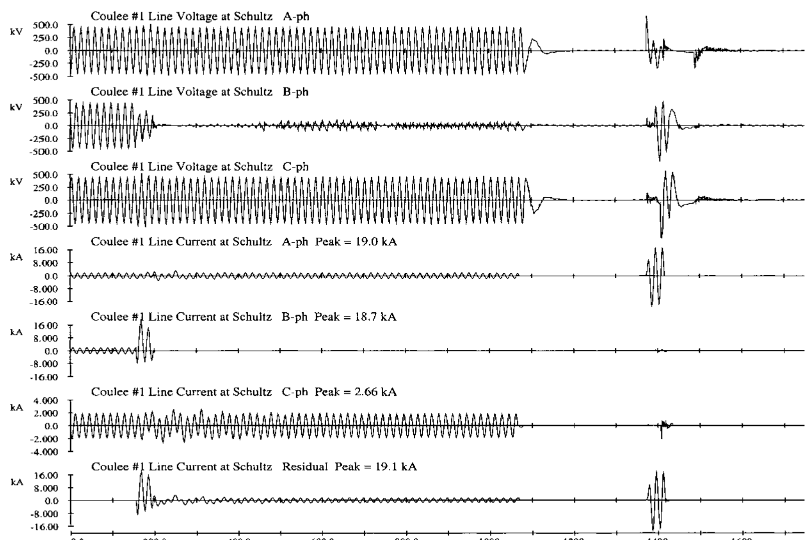
Hybrid SPS Trip & Second Fault – Schultz DFR



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Series Compensation

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Series Capacitors

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Series Compensation

- Series capacitors compensate for the inductive reactance of transmission lines by reducing the total reactance of the line.
- The lines become electrically shorter (less total reactance) and line loading can be increased.
- Series capacitors also improve stability by reducing the line inductive reactance. This will allow for higher loading before the transmission line begins to consume reactive power (surge impedance load SIL). This will reduce the system voltage. Voltage stability problems can occur when the system is heavily loaded.
  - An unloaded or lightly loaded transmission line has a net capacitive reactance and supplies reactive power MVARs to the power system. This helps to support the voltage. When this capacitive reactance is too great shunt reactors must be inserted to prevent the voltage from becoming excessive. During periods of light loading, the system dispatchers also switch some 500kv lines out of service for voltage control.

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Series Compensation

- BPA installs series capacitors on longer 500kv lines to increase power transfer and to improve system stability.
- Currently BPA installs series capacitors only on 500kv lines.
- Series capacitors are normally installed at the line terminals with only a couple of exceptions.
- Lines are normally compensated between 35% and 50%.
  - The California Oregon Intertie COI is normally 60% compensated by two series capacitor installations distributed along the corridor
    - Compensation is increased to 80% by inserting a third group of series capacitors when the system requires increased compensation
      - RAS schemes and the Fast AC Reactive Insertion Scheme inserts these capacitors when necessary..

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Series Compensation

- FACRI
  - The purpose of the Fast AC Reactive Insertion scheme is to improve transient and voltage stability for certain outages in the WECC network
  - What does FACRI do?
    - Insert selected shunt capacitors
    - Trip shunt reactors
    - Insert the third group of series capacitors on the California Oregon Intertie
- Series capacitors have an additional benefit during solar storms
  - Severe solar events can create varying earth surface potentials across the Northwest. These varying earth surface potentials cause low levels of dc current to flow in the power system through the grounded neutrals of power transformers. DC current will drive a transformer into ½ cycle saturation. If the saturation is severe enough the transformer can be damaged. Series capacitors block dc current.

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Series Compensation

- BPA Series capacitor installations
  - Series capacitor protection
    - Metal oxide varistors MOV. MOVs clip the peak voltage across the capacitors when the through current exceeds the capacitor rating.
      - MOV protective levels are normally from 2.0 pu to 2.5 pu of the rated voltage of the capacitors
    - At higher levels of current the arc gap and bypass breaker operate to bypass the capacitor group.
      - For close in fault operations where the fault current exceeds the bypass current level the series capacitor on the faulted phase will bypass. The capacitors on the un-faulted phases will remain in service.
    - Some series capacitors do not need high speed bypassing and are protected by MOVs and bypass breakers only.

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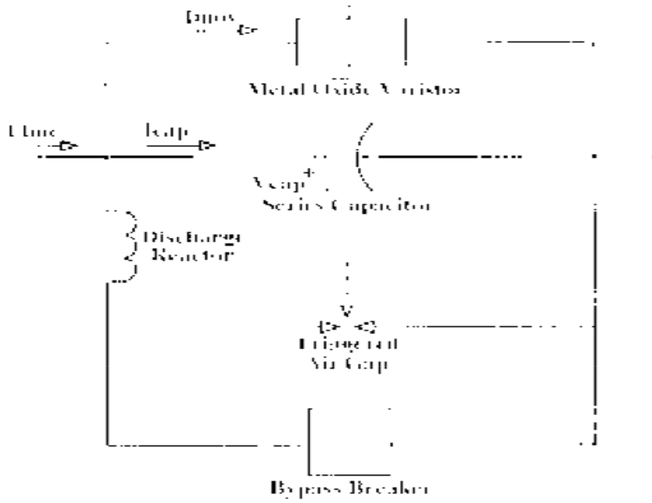
Series Cap on the Line - Schematic



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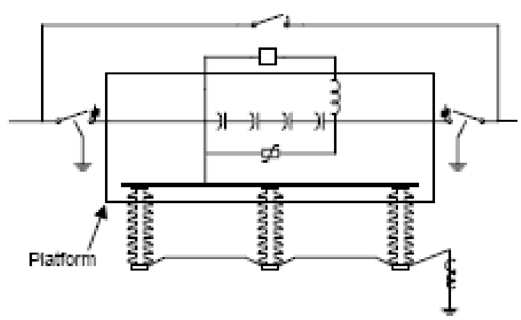
Series Compensation

- Typical series capacitor with MOV and bypass breaker
  - Typical Ratings: 31.6 Ohms, 546 MVARS, 2400 amps, 3800 amps for 30 min, MOV 103 MJ per phase with 2.3 pu PL



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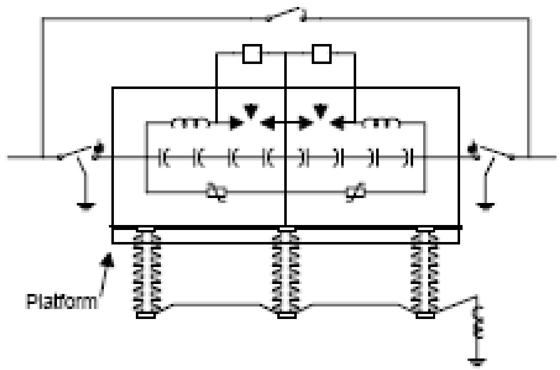
Series Compensation

- Typical series capacitor with MOV, spark gap, and bypass breaker
  - Typical Ratings: 25 Ohms (12.5+12.5), 546.8 MVARS, 2700 amps, 4100 amps for 30 min, MOV 23.5 MJ per segment per phase with 2.2 pu PL



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Series Compensation

- System Impact
  - The capacitive reactance Xc of the series capacitors is in series with the system inductive reactance Xl. This creates a series resonate circuit that typically has a sub-harmonic resonant frequency of from 5 to 30 Hz.
  - Transients on the power system such as those created by line faults and switching can initiate a sub-harmonic oscillation for up to 1 second.
  - During faults this oscillation is superimposed on the fault currents causing line relays to measure a varying fault impedance. This can cause the relays to over reach. Settings must account for this.

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Series Compensation

- System Impact
  - After a fault is cleared the sub-harmonic oscillations are also superimposed on the load currents. In a heavily loaded system these oscillations can cause problems for relays on adjacent lines.
- Affect of series compensation on transmission line relays.
  - Distance relays (impedance relays) are most affected by series compensation, heavy loading and the associated system disturbances.
  - The impedance of a faulted transmission line is mostly inductive. The distance relay measures this inductive reactance to the fault.
    - Series capacitors reduce the electrical length of the line. The settings of the under reaching elements must account for this when series capacitors are in the zone of protection.

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Series Compensation

- Affect of series compensation on transmission line relays.
  - Depending on the location in the line of the series capacitors, the net measured reactance to the fault may be capacitive rather than inductive making the fault appear to be in the reverse direction.
    - Modern relay design accounts for this.
    - When series capacitors are located at the line terminals BPA installs the line pts on the line side of the series capacitors.
  - When series capacitors are located behind the relays, the faulted phase voltage at the relay location may actually rise for some line faults rather than depress.

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Series Compensation

- Traveling wave relays are not affected by current reversal, voltage reversal, sub-harmonic oscillations, out of step, or heavy load.
  - They can operate using the standard audio transfer trip equipment that is available from the analog microwave system.
    - Large numbers of traveling wave relays were installed in the BPA 500kv system in the 1990s.
- Current differential relays are not affected buy the system affects of series compensation. They can also be set more sensitive providing an increased ground fault resistance coverage.
  - A few sets are in service in the BPA system where digital communications paths are available.
  - As BPA upgrades the communications system more stations can accommodate modern line differential relays. BPA plans to use more line differential relays on series compensated lines in the future.

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Series Compensation

- System Impact – Fault Studies
  - Fault study programs must account for the operation of bypass MOVs and gaps as the calculated fault currents exceed the actual capacitor current.
    - The BPA fault study program uses an iterative process to simulate the operation of the MOVs in parallel with the capacitors. As the calculated currents increase above the rated series capacitor current rating the MOV resistance is decreased.
    - Steady state calculations still cannot include the affect of transient phenomena such as system sub-harmonic oscillations.
    - For series compensated lines transient analysis studies using EMTP are used by BPA to confirm the final relay settings.

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Series Compensation

- The Electromagnetic Transient Program EMTP software has accurate models of power system components including transmission lines, generators, transformers, shunt capacitors, series capacitors, shunt reactors, and power circuit breakers.
  - The output accurately reproduces actual system fault and switching events.
  - The accuracy of the EMTP models is checked by comparing its calculated data to digital fault records and relay event records from actual line fault operations.
  - Prior to staged fault testing the faults are modeled using EMTP.
    - After the tests the EMTP generated fault data is compared to the actual recorded fault data.
      - BPA used extensive staged fault testing to check the operation of the protection (MOVs, spark gaps, bypass breakers, etc.) of series capacitors prior to releasing them for service.

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Communications Schemes For Protective Relays

- The BPA communications system is built around an analog microwave radio system.
- The analog radio equipment is now obsolete and BPA is currently upgrading the system to modern digital equipment.
  - Much of the analog microwave system remains in service.
- Most of the communications related functions that are required to operate the BPA system are carried over the BPA owned communications systems

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Communications Schemes For Protective Relays

- BPA also connects to, and uses communications systems that are owned and operated by other utilities as necessary when interconnections are required .
- BPA uses very little leased communications paths.
- Some of these communications related functions include
  - BPA phone system
  - SCADA
  - Metering and telemetering
  - Remedial Action Scheme inputs and controls
  - Generation control
  - Transfer trip for the line relays

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Communications Schemes For Protective Relays

- Audio Transfer Trip Equipment (tone gear)
  - Analog radio systems provide voice grade audio channels (4khz) for the protective relays and Remedial Action schemes
  - BPA audio transfer trip equipment uses Frequency Shift Keying Modulation FSK to send the protection signals to the remote terminal.
  - An FSK channel continuously transmits a guard frequency. When a keying input is initiated the frequency shifts from the guard frequency to the trip frequency. The receiver detects this shift and energizes an output.
  - Advantages of FSK Modulation
    - Fast operating time
    - High dependability
    - High security

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Communications Schemes For Protective Relays

- Audio Transfer Trip Equipment (tone gear)
  - The tone equipment divides the voice channel into sub-channels.
    - In older tone equipment the sub-channel spacing is 340hz and the nominal operating bandwidth is 170hz.
    - Guard and trip frequencies are shifted +/- 75 hz from the center frequency. Guard to trip is a 150hz shift.
    - Two sub-channels are assigned within the frequency band.
      - For many years BPA has used this two tone transfer trip equipment for protective relaying. Much of it is still in service.
    - Interfacing older electromechanical, static, and microprocessor based relays to the tone gear is done by a separate transfer trip interface panel.
      - Main components of the interface panel
        - Tripping relay. The MWT relay trips the line breakers.
        - Direct tripping logic
        - Permissive tripping logic
        - Miscellaneous functions: counters, targets, alarms, cutout switch

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Communications Schemes For Protective Relays

- Transfer trip functions
  - Direct trip function
    - Direct tripping simply sends a breaker trip to the remote terminal.
      - For added security the direct trip function requires both tones to shift before a trip allowed.
      - Usually the under reaching zone 1 and instantaneous ground elements key direct trip to the remote terminal.
      - Backup trip functions such as a transformer differential trip on transformer terminated lines also key the direct trip function.
  - Permissive trip function
    - The permissive logic will transmit the permissive tone (tone 2) to the remote terminal if a local zone 2 or instantaneous ground overcurrent relay pickup. It will output a breaker trip if it receives a permissive tone from the remote terminal at the same time.

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Communications Schemes For Protective Relays

- Remedial Action schemes and new protection schemes require faster end to end communications through put times.
  - The channel spacing and bandwidth of the tone shelves was increased from 340hz and 170hz to 680hz and 340hz with a tone shift of +/-150hz from the center frequency.
    - This gave an end to end trip time of 1 cycle (16.66ms); 12ms for the transmitter, receiver, and output relays plus 4 ms for the microwave channel delay.
      - In newer equipment the end to end trip time was reduced by 3 to 4 milliseconds by switching from mechanical output relays to solid state outputs.
- A 4khz audio channel can be divided into 4 680hz sub channels.
  - The latest versions of the tone gear for RAS and protection provide 4 protection functions.
    - Four function transfer trip equipment is the BPA standard today when protection communications is over audio channels.

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Communications Schemes For Protective Relays

- Direct Fiber Optic Connections
  - When the lines are very short such as from a substation to a generating station or industrial site, or to a nearby customers substation, direct fiber links are commonly used.
  - Modern current differential relays are most commonly used for these applications.

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Communications Schemes For Protective Relays

- Digital Communications
  - BPA is phasing out its analog microwave system and replacing it with digital communications.
  - Digital Radios and digital microwave paths are used in some locations.
    - Microwave repeaters are generally located on mountain tops and are difficult to maintain, particularly in the winter. BPA will phase some of these out when they are no longer needed.
  - Digital communications in most of the BPA system is being updated to fiber optic paths. The fiber optic cables are run along the transmission line corridors, and are generally strung on the transmission towers.
  - Digital communications is set up as a Synchronous Optical Network SONET using a closed ring topology.
    - The closed ring topology Provides redundant paths to each node in the ring. These paths are not in the same corridor, and are truly redundant.
    - When a path failure occurs between two nodes the traffic is re-routed to the other path.

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Communications Schemes For Protective Relays

- Digital channel banks and multiplexers provide synchronous communications channels.
  - Currently at least 1 64kbps synchronous channel is allocated to each RAS shelf and to each set of protective relays.
  - Modern transmission line relays have relay to relay communications capability and do not need external transfer trip equipment. BPA is increasing the use of relay to relay communications for transfer trip functions.
  - With the increasing access to synchronous communications channels, BPA is also considering adding more line differential relays, even at 500kv where system transients cause problems for distance relays.

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Questions or Discussions