

10.2.7 Establishing a Water Supply

Probably the most important step when controlling a Level III incident is establishing a water supply that will be plentiful and consistent. The plan will be to set up two (2) 4000 or 6000 gpm pumps to supply water. Also, it will be necessary to use a 14-20 inch pipeline from the fire pumps to the fire main manifold which will be placed on the upwind edge of the location. This would enable us to use the water supplied at 153 psi discharge to reach the fire main and the monitor sheds with proper pressure.



10.2.8 Water Supply Storage



10.2.9 Water Supply Calculations

A blowout on fire requires a tremendous volume of water. For example, the following calculations show how fast a 1,000,000 (24,000 bbl) pit would be emptied using various capacity fire pumps.

$$1,000,000 \text{ gallons} / (6,000 \text{ GPM} + 6,000 \text{ GPM}) = 83 \text{ minutes}$$

$$1,000,000 \text{ gallons} / (6,000 \text{ GPM} + 4,000 \text{ GPM}) = 100 \text{ minutes}$$

$$1,000,000 \text{ gallons} / (4,000 \text{ GPM} + 4,000 \text{ GPM}) = 125 \text{ minutes...or 2 hours and 5 minutes}$$

In reality, the output of a 4,000 GPM pump is about 3,200 GPM.

NOTE: Some of the calculations below have been rounded.

Using 23,200 GPM the water usage is 6,400 GPM.

$$100,000 \text{ gal} / 6,400 \text{ GPM} = 156 \text{ minutes}$$

$$156 \text{ minutes} / 60 \text{ min per hour} = 2.5 \text{ hours water supply}$$

A 30% recovery rate extends the water supply to just over 3 hours

$$2.5 \times 1.3 > 3 \text{ hours}$$

If 1,000,000 gal is used in 3 hours, then 3,000,000 gal is used in a 9 hour work day.



The average water well in the S1 field produces about 190 bbls/hour

190 bbls/hour x 42 gal/bbl = 7,980 gal/hr.

With the pit full (1,000,000 gal) in the morning 2,000,000 additional gallons would need to be produced in a 9 hour period.

2,000,000 gal/9 hours = 220,000 gal/hour needed production

(220,000 gal/hr) / (7,980 gal/hr/well) = 27 water wells.

The alternative would be to construct 21,000,000 gallon pits.

On hand supply would then be 6 hours with the need to replenish 1,000,000 gallons in 9 hours.

1,000,000 gal/9 hours = 110,000 gal/hr replenish rate

(110,000 gal/hr) / (7,980 gal/hr/well) = 14 water wells.

To replenish the dry pits over night the water volume would be as follows:

24 hours – 9 hours = 15 hours to replenish the pits

2,000,000 gal / 15 hours = 130,000 gal/hr

(130,000 gal/hr) / (7,980 gal/hr/well) = 16 wells.

NOTE: If necessary, water wells could be augmented by water tankers. Drilling for water wells and constructing water storage pits is expected to be difficult within the Ratana field due to the hardness of the surface. Water supply within the Ratana field will most likely be from one of the reservoirs in the area.

NOTE: if the above minimums prove to be logistically unfeasible, then operations would necessarily have to be planned around the water supply that *IS* available.

10.2.10 Civil Works Equipment

A critical point for any major onshore blowout is having the adequate heavy civil works equipment available. If the well is on fire, a D8 bulldozer (or larger) with a Cat Model 57 or Hyster D89C winch is typically used.

The civil works equipment (dozers, cranes, front end loaders etc.) and trucking must be locally obtained. Normally the main civil works equipment problem is the lack of large dozers equipped with a winch. Equipment will need to be maintained and have a working equipment inventory. It may be necessary to mobilize a skilled heavy equipment mechanic with the fire fighters to help keep the equipment running.

Machine shop services needed from custom capping equipment (ex: stingers, crossovers, custom flanges) should be identified and located. The Incident Manager should assign someone to locate these providers.

PTTEP Thailand will need dedicated support personnel working in the areas of transport, material acquisition, logistics, contracting, accounting and communications if a major blowout occurs.

It will be wise, at some point, to gather up the blowout task force and run a test drill on response to a blowout emergency scenario. Minute by minute well reports can be generated to simulate the type of information received from the field to the task force. The response steps are taken including vendor call ups. After the simulation is completed, the exercise is criticized and then edited based on the results of the simulation.



10.2.11 Role of a Rig Contractor

The key to successful blowout control is fast and efficient mobilization of the required support. The following list is not complete but can be used as a reference as to what may be required. The greatest key team member if a blowout is experienced will be the rig contractor, especially if they are experienced in how to acquire local available services, equipment and materials. The rig crew may be needed to assist the well capping specialists. PTTEP Thailand should hold a pre-planning meeting with the rig contractor and discuss these and any additional points:

- Third party billing and purchase order system
- Cash flow assistance (must maintain good credit with local vendors)
- Increased rig crew pay for hazard duty (triple time is not uncommon)
- Added staff from rig contractor to handle logistical duties
- Increase camp space options.
- Spare equipment sources (ex: BOPs & choke manifolds)
- Welding/fabrication sources
- Oilfield supply sources
- Implementation of the fire water system (water wells, pits and pipelines)

10.2.12 Typical Dimensions of Major Firefighting Components

- **ATHEY WAGON:** three pieces as follows: carriage 26.5' x 8' x 5.5' (15000 lbs), long boom 41' x 4.5' x 2.5' (3000 lbs) short boom 25' x 3' x 2.5' (1500 lbs). Two atthey wagons required for a major rig fire.
- **FIRE PUMP:** integrated on skid (pump capable of 4000 GPM w/425 feet of head): 13' x 7' x 7.5' (10000 lbs). Two pumps required for a major rig fire.
- **TRANSFER PUMP:** integrated on skid (pump capable of 4750 GPM w/100 feet of head): 13' x 7' x 7' (9000 lbs). Two pumps required for a major rig fire.
- **PIPE RACK UNIT:** discharge piping and suction lines for pumps: 33' x 7' x 7' (20,000 lbs). One unit required.
- **AIR COMPRESSOR UNIT:** integrated on skid with priming pump to start fire pumps: 10' x 6' x 4.5' (3000 lbs).

10.2.13 Example Equipment List

The following is an example listing of the equipment and materials that will be required for major blowout scenarios. Not all of these items will be required nor is it a complete list as all blowouts are different and not all needs can be anticipated.

Worst Case Underground Blowout

- The major items that may be required are as follows:
- Cement pump and cementing lines
- Cementing batch mixer or additional mud mixing tank
- Cased hole wireline unit
- Pressure / temperature log, perforators, drill collar severing tool, gyro

- Possible additional stimulation pumps (higher rates and/or pressures required)
- Centrifugal pumps (mud transfer and circulation)
- Suction hoses and mud transfer lines (additional mud tanks and water pit)
- Sack cement and pure bentonite for bentonite – cement – diesel oil – plug
- Medium & coarse LCM materials (KwickSeal, mica, nut plug, ground CaCO₃)
- Additional mud products for quick mix mud (gel, water, caustic, barite, lignosulfonate).
- Additional water supply (possible additional water wells and water storage pit)
- New seismic to map gas flood front (sustained high rate gas flow).
- Re-survey surface location from fixed reference point (severe gas flow)
- Rate gyro run on drill pipe for better relief well target (severe gas flow)
- Initiate relief well planning (severe gas flow, potential loss of surface access).
- Additional mud storage tanks.
- Snubbing unit and tools (drill pipe off bottom, drill pipe plugged, hole in casing).
- Inflatable packer (unable to dynamically kill, due to a hole in casing)
- Handheld radios for site communication

Surface Blowout without Fire or Rig Removal

The major items that may be required are as follows:

- H₂S/Paramedic services: detection equipment, breathing air equipment
- Major civil works contractor to provide: 2 dozers (Cat D7), excavator, front end loader, compactor, 150 ton tracked crane (w/hook & bucket), probable 100 ton hydraulic crane, lube/fuel support, forklifts equivalent to a cat 950 and associated support personnel and skilled operators.
- Welding/fabrication contractor: to provide welders, welding supplies and equipment, nearby fabrication shop
- In country delivery/barge services
- Machine shop: to provide custom toll fabrication and modification
- Pumping/cementing services: to provide cementing unit, batch mixer/blender, spare tanks, pump lines, possible additional horsepower units.
- Medical evacuation services
- Well capping specialists
- Fire pumps and associated equipment
- Blowout technical advisor
- Two air compressors (185 CFM 150 psi) for air tools and engine starting
- Replacement valves, wellheads or BOPs. Additional ram blocks and packers, associated studs, nuts and ring gaskets.
- 75 kg wheel mounted fire extinguishers, additional smaller fire extinguishers

- Fabrication steel including (1/2" – 3/4" round stock, 1" steel plate, H-Beams)
- Dry ice and insulated transport box
- Teflon tape and thread lubricant
- Epoxy thread locking kits
- Cotton Rags
- Bottled drinking water
- Rest location for well capping specialists
- Flare pistol or rifle with flares
- Video and still photographer to record operations
- Location security and location access control of non-essential personnel
- Evacuation of local villagers, livestock
- Water well driller, casing and pumps (additional water supply requirement)
- Portable generators and light plants
- Misc. common oil field supplies and tools
- Ten handheld radios
- Diesel powered centrifugal pumps for fire protection, water transfer
- One reel of 1" to 1-1/8" (25 to 28 mm) soft lay steel cable for tie-downs, snub down lines and winches.

Major Rig Fire

The following services will be required:

- All of the above equipment (1.5.1 and 1.5.2)
- Support mats for pumps and equipment
- Four D8 equivalent dozers (prefer low ground pressure D8N dozers with cat Model 57 winches)
- Two cat Model 57 winches or those compatible with the dozers on location with power forward/reverse and no neutral (free spool) position
- Large walking crane > 150 ton with large boom, hook and bucket
- Two large cat 235 excavators
- Two cat 950 or 966E front end loaders with bucket and forks
- 2", 3" and 4" A36 steel plate (1m square)
- Structural steel: channel iron, box tubing, H beams, round tubing
- Air conditioned rest and paramedic stations
- River rock and gravel for location stabilization
- 6" pipeline pipe and 8-5/8" – 9-5/8" 8RD casing
- Water pumps for pipeline
- Light plants and generators

- Carpentry crews and materials (plywood, boards, nails, etc.)
- 50 ton rough terrain crane w/slides for assembling firefighting and capping tools
- Pipeline welding machines
- Anchor setting machine and anchors (auger type)
- Construction concrete and rebar
- UPS power supply for operations center
- 100000 psi discharge lines from Halliburton, Schlumberger or BJ (steel or Coflex)
- Additional horsepower from Halliburton, Schlumberger or BJ
- Over 50 handheld radios with extra batteries and multiple rechargers
- Over 5 long range mobile units
- Two international phone lines as the on-scene command center
- 1", 3/4" and 1/2" wire rope and cable clamps for slings
- Centrifugal trash pumps to pump out sumps, excavations and cellars

Normal Oilfield Services

Other considerations include such services and supplies as are normally used in oilfield operations.

The following is a partial list of the types of services or materials which may be needed.

- Oilfield Services and Materials:
- Mud Supplies and Mixing Equipment
- Civil Works (earth moving)
- Water Tanks
- Environmental
- Rental Tools
- Communications
- Cementing Stimulation Services
- Slick Line
- Open hole E-Line
- Cased Hole E-Line
- Well Testing
- Wellhead Maintenance
- Hot Tapping

Other Requirements

BOP and well control equipment will likely be rented locally but it may be necessary to bring in a specialized capping stack from Houston (Weatherford).

10.3 BLOWOUT SCENARIOS AND COMMENTARY

10.3.1 Underground Blowouts

Underground blowouts are the most common type of blowout. These blowouts generally occur when loss of circulation is experienced while circulating out a kick.

10.3.2 Basic Control Procedures

It is common for field personnel to fail to recognize that an underground blowout is occurring since many times they are focused on curing loss circulation. The following are signs of underground flow:

- Initial drill pipe and casing pressure increase followed by decrease. Typically, drill pipe pressure will drop to zero and then increase and casing pressure may not change very much.
- Gas, oil or salt water to surface on drill pipe caused mud jetted out of drill pipe by flow and replaced with blowout fluids (no float).
- Unable to get mud returns with blowout fluids at surface in annulus. Mud carried out in loss zone by mud.
- Able to strip up or down with no change in annulus pressure. Controlling pressure is fracture pressure or pore pressure at the loss zone.
- Thermal anomalies seen in temperature log. Higher temperatures seen opposite shallower loss zone (flow from bottom). Lower temperatures seen opposite loss zone (flow from top rare).
- No direct indication of pressure communication between drill pipe and annulus.

Underground flow begins when normal drill pipe circulation pressure is lost. It is common for this to occur when the leading edge of a gas kick is circulated past the last casing shoe or hits surface (choke line restriction). After underground blowout gas flow starts, mud is quickly jetted out of the well bore. If pumps are shut down the drill pipe pressure will stabilize slightly above the annulus pressure. This difference results from flowing frictional pressure drop in the annulus and/or the hydrostatic of gas lifted water. The greater this difference the higher the annulus friction or fluid density will be. If the bit is significantly off bottom and the drill pipe string is free, the drill string should be stripped through annular to bottom to facilitate the control. This is easily done, as no mud needs to be led out of the well when stripping into an underground flow. This is facilitated if there is a drill string float. If a DP float is not installed, BPV can be installed to allow making up connections, however, BPV in the string will limit wireline work and should be avoided if possible.

In the underground blowout it is often necessary to run logs in the DP so obstructions should be avoided.

When underground flow occurs, run a pressure/temperature log in the drill pipe to locate the loss zone and define flowing bottomhole pressure. Blow nozzles out of bit to minimize pressure drop and risk of nozzle plugging with loss circulation materials. If not possible, consider perforating or severing the drill collars. However, perforations in DC are at best difficult to accomplish as the bore limits the size tool that can be run via wireline. Consider running a rate gyro for a better relief well target or in case the well is sidetracked after control is gained.

Mobilize additional mud storage tanks if necessary. Mobilize cementing batch mixer if available. Mix and store at least one additional hole volume of mud on location. While mixing mud, bullhead water down the annulus to loss zone to minimize annulus surface pressure and keep possible H₂S off of casing, wellhead and BOPs. This will assist in interpreting the temperature log by defining a

temperature gradient at loss zone. Fracture extension pressure can be estimated from surface injection pressure over water hydrostatic to loss zone.

Slow the annulus rate and continue annular water injection with cementing pump. Pump down drill string at 90% of maximum possible rate using rig pumps with water until pressure stabilizes. Record stabilized pressure and rate. Increase the pump rate to maximum and record stabilized pressure and rate. The stabilized pressure on drill pipe is a function of the annulus two-phase flow hydrostatic and friction. If single flow can be achieved in the annulus, the well can be dynamically killed with the rig pumps. The drill pressure for single phase water flow can be accurately determined. If this pressure is nearly achieved during the test, the well can be easily killed using kill weight mud instead of water. Loss circulation materials can be added to the mud to help get a static kill after the pumps are shut down. If a dynamic kill with mud or water is not achieved, the recorded stabilized two phase flow pressure developed during the attempted kill in combination with the results of the pressure/temperature log can be analysed to determine what would be required. Gunk squeezes (diesel oil-bentonite-cement) or high density pills (barite pills) could also be used depending on the results.

10.3.3 Surface Blowout/Not on Fire

During drilling, a kick must be taken before the well can blowout. Generally, all surface blowouts are a result of equipment or operational failure of the BOP system, wellhead equipment or near surface tubular during a kick. Some blowouts are a result of an underground blowout breaching to surface. Surface breaching generally eliminates surface access making a relief well the only viable option. Surface intervention of a breached well is only possible if the breached is stable and downwind of the well. And flow rate is low. A surface blowout that is not on fire would be either in the BOP equipment, wellhead equipment, through the drill pipe or during testing. These are the four surface blowout scenarios that will be evaluated.

Likely Surface Blowout Scenarios

Flow may not ignite if low heat content gas is produced (low C_1 fraction, N_2 and CO_2) and particularly if free water is produced with the gas. Dry gas production makes ignition of a blowout very likely. High internal corrosion/erosion rates (combination of high velocity, CO_2 and free water) can complicate control. H_2S and CO_2 may be present in very low concentrations.

Annular Blowout Flow

If the annular blowout flow is occurring above the wellhead, then a failure is at the BOP flanges, bonnet seals, ram packer, steam packing or outlets has occurred. Generally, the failures are not catastrophic but start as leaks that cut-out the affected BOP area and become blowouts. Quick detection and proper response can keep the problem from getting any worse. The first option is to isolate the leak if possible by closing the lower rams. Leaks can then be plugged by pumping plugging materials through the kill lines. In some limited cases, gas hydrates form a temporary plug, then melts, and the leak restarts, and then hydrates re-form. This cycle of leakage and the formation of hydrates, most probably will cause the leak to worsen due to erosion. The application of water ice (better) or dry ice (solid CO_2) at the leak can help hydrates form or reform and keep them from melting. Pressure can be temporarily relieved down the choke line while preparing to fix the leak and/or re-torque flanges. In all these cases response time is limited. Action must be taken at the well site immediately. Ultimately, severe cut out of equipment can eliminate all of these options. Removal and replacement of cutout equipment would be required. This could require removal of the drilling rig and would require a well capping specialist.

A minor leak at or below the wellhead could also be controlled, as discussed before, with plugging materials or dry ice induced hydrates.

Drill Pipe Blowout Flow

Most drill pipe blowouts occur either while tripping into swabbed in gas or from failure of surface safety valves and pump in lines. It can be impossible to close a ball type safety valve against strong flow. Drill pipe blowouts can be prevented by using drill string float valves. An Oil Base Mud will increase the risk of a drill pipe blowout.

Tripping into oil mud saturated with gas leads to drill pipe blowouts if a float valve is not used. Immediate well site control could be accomplished by stabbing a safety valve. Leaks in threads could be hydrated off with dry ice or plugged with junk shots.

A method used to control drill pipe flow is by stabbing a double ram BOP with inverted slip ram under inverted pipe ram, drilling spool, single blind ram, 2 m long bell nipple.

- Tool joint is spaced out between the rams, diverter and pump in lines are hooked up to the spool.
- The inverted slip ram is closed.
- The inverted pipe ram is closed
- The diverter line opened and the blind ram is closed
- The diverter line is choked back and control is accomplished conventionally through the pump in line.

Small BOPs (7-1/16") have been successfully used to cap drill pipe flow in this manner with drill pipe suspended in rotary or BOP. A hydraulic crane has been used to place the BOPs over the drill pipe with the rig in place. With are on space out, the drilling spool can be eliminated by using the outlets on the upper BOP. BOP equipment as small as 4 1/16" have been used successfully on small drill pipe and tubing blowouts. On lower pressure blowouts the inverted slip ram can be dropped as the inverted pipe ram that will catch on the upset or collar.

If the well breaches to surface, it is imperative that wellbore pressure be released before the rig is cratered. Rigs have been lost because the location was abandoned with the BOP still shut in on the annulus with the well breached to the surface. The first step to take is to open the choke line directly to a flare line. If the flow in the broach is not impacted, then opening the BOP stack and letting the well blow vertically must be considered. Ideally, the rotary slips and bushings should be removed and drill string slacked off nearly totally on bottom with a tool joint rested against a ram. Remove all loose tools away from rotary and drop the travelling block out the V-door or pull up high in derrick. Shut down all sources of ignition, evacuate rig and open all rams from BOP remote station to let well flow vertically and drop the drill pipe. This will likely result in the well bore bridging. Most open hole blowouts end from natural formation bridging. Bridging can be induced if wellbore pressure is suddenly lowered and annulus is partially filled with helically buckled drill string. Many cratered rig blowouts requiring relief well control have been controlled in this manner by the wellsite crew.

Whenever there is a gas risk at surface, firefighting equipment should be positioned and manned (example: well testing). The rig fire main should be charged and fire hoses in place and operated. The fire hoses need to be coupled away from the potential fire area and positioned upwind from the well head near the large wheel mounted fire extinguishers. Men operating the fire extinguishers can then go in toward the fire under protection from water spray from the fire hoses. Fire hoses and men will not burn if a water curtain is maintained between them and the fire. A water spray can prevent unwanted ignition. The large fire extinguishers can extinguish smaller well fires and used in combination with water from the fire hoses.



The key to successful use of the large fire extinguishers is to:

- Fully stretch out the discharge lines prior to operation.
- Work as close to the fire as possible on an upwind size.
- Start with water to cool area around fire prior to opening valve on extinguishers.
- After cooling the fire as much as possible with available water, open at least two extinguishers simultaneously and direct powder at base of flames.
- Fully discharge extinguishers and continue applying maximum available water to prevent re-ignition.
- If the fire does not extinguish or re-ignites, then there is insufficient water flow out the hoses. Larger pumps, more hoses or fire monitors are needed.

Ideally, the rig contractor should have a team with the assigned responsibility for this activity. At least two men are needed on each fire hose, two men on each extinguisher and one man in heat reflective asbestos dress as a rescue man. The other should wear normal safety equipment, long sleeve cotton coveralls and cotton gloves and be thoroughly soaked with water. A wet cotton towel stuffed around the head, neck and face and into the coverall will provide additional protection. Practice drills of firefighting team should be considered.

Capping & Control Procedure (most likely Blowout)

Major surface leaks during kick handling procedures in the BOP equipment should be the most likely type of surface blowout.

The use of junk shots to plug surface equipment leaks should be understood by wellsite supervisory personnel. Successful junk shot application is time dependent as the leak opening always grows. A junk shot is accomplished by removing the check valves (to prevent line plugging) and loading 1 to 2 meters of kill line with rope fiber and walnut hull. The best fibers are the Kevlar or polypropylene types (higher tensile strength than hemp or cotton). If rope is to be used, the rope pieces should be 6" long 3/8" diameter, and frayed with tight knot in the middle of the rope. The walnut hulls should be medium and coarse materials. Mud loaded with 10 ppb medium Kwik-seal should be used to displace the junk shot (Kwik seal is a blend of fiber, granular and flake material). The junk shot will bridge and seal the leak allowing conventional control operations to continue. Additional junk shots can be pumped at times to re-seal the leak. Large leaks have been controlled by pumping golf balls a head of the junk shots. A 5 gallon bucket of pre-cut rope and other bridging material can be kept on the rig to quickly inject a junk shot to seal a surface leak. Time is saved if this is done and a rig scavenger hunt for sealing materials is not required.

Leaks can be worked on or stabilized until a fix is possible by relieving pressure. Flow out wide open chokes down the flare line should be considered. It is better to open the well up on flare line than to allow pressure containing equipment to cut-out.

The ram blocks of Cameron type "U" preventers can be replaced by well capping specialists while the well is blowing out vertically. Steps taken involve opening all BOPs to eliminate any back pressure, applying water deluge, hydraulically opening the bonnets and replacing ram blocks. This is possible as the high velocity gas flow produces a vacuum from a Venturi effect in the BOP and the bell nipple located above the BOP to be repaired. (The bonnets can be remotely hydraulically operated and quickly opened. The Venturi effect draws air into the BOP and very little gas escapes.)



10.3.4 Surface Blowout/Well on Fire

A hot fire causes rig collapse within minutes. Melted steel and debris will cover the BOP and wellhead causing severe damage to the wellhead. If this happens, the well most probably will have to be capped on exposed casing. Blowout control operations can take weeks

10.4 CAPPING STRATEGY

10.5 SURFACE INTERVENTION, FIREFIGHTING & CAPPING STRATEGY

It is not possible to discuss every eventuality which may arise during an offshore blowout. However, a general discussion of the equipment and techniques typically used on a major offshore blowout/fire is needed. Appendix B offers a general discussion regarding capping operations. The following intervention techniques are those which may be employed after the initial mobilization and set-up of the primary support vessel has been completed.

10.5.1 Debris Removal

The initial phase of the intervention will involve clearing damaged or unnecessary equipment from the structure. This is done to provide working room as well as to remove valuable equipment from danger. The intervention team attempt to re-board the structure under the covering water spray from either a tie-in of the primary firewater ring or from the primary support vessel. Once on board, the intervention team will assess the situation and proceed accordingly. The crane on the support vessel can be used to remove all equipment which is accessible. In certain situations it may be possible to use the existing platform crane(s). This may not be feasible since the crane may be damaged beyond repair or it may not be practical to re-connect power to the crane.

10.5.2 Fire Control

To safely deal with an offshore blowout, the intervention team must have the capability to apply large volumes of water. This should be done to cool the area and allow wellhead access or to aid in the prevention of ignition while working in proximity to the flow. Portable monitors will be placed at the point where covering firewater is needed. There are three feasible sources of firewater. They are from:

- Existing firewater ring (provided it is operational)
- Firewater pumps on standby boats or barges (vessels of opportunity) or
- Portable firewater pumps (from well control vendor or others)

During the intervention project, usually following debris removal, attempts will be made to place firefighting monitors (outlets) on the structure at points that will be determined by the incident, per Figure below. If possible, attempts may be made to utilize the existing deluge piping on the structure. This has been accomplished on platform fires and blowouts in the past and has proven very beneficial to the project. If the existing firewater ring is not energized from the pumps on the platform, an external tie-in of portable pumps at the splash zone (boat landing) is recommended. This is best accomplished if a vertical riser is in place beforehand. However, this can be installed in by the intervention team if necessary.

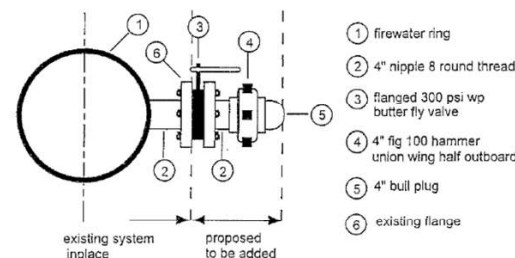


Figure Example of a tie-in to the firewater ring for portable monitors

Portable firewater monitors (type rated at 1,200 gpm) placed on the structure will provide precise placement of water for cover and cooling purposes. If the firewater ring cannot be utilized, an alternate will be to install temporary conduits such as large, low pressure hoses from the support vessel to the monitors on the structure. If space and conditions allow, portable firewater pumps can be placed on the structure and their suctions charged by the pumps on the support vessel.

Firewater application from standby boats is a viable option and has certain advantages and disadvantages. One advantage is that the boat can be mobilized to the site and used if the platform is abandoned. Therefore a re-start of engines and re-boarding of the facility may not be necessary. Firewater supply from a barge or boat necessitates that the boat come alongside the burning or blowing well platform. This places the boat and the crew closer to the problem and increases the potential for injury and damage if proper procedures are not employed. Firewater support from floating platforms is controlled by the wind and seas. Precise application is required to protect the intervention personnel, and wave action (greater than $\frac{1}{2}$ to $\frac{3}{4}$ m) may prevent the boat from applying the water stream onto the point of interest with sufficient reliability. Therefore this method may require more stringent weather windows for close work by the intervention team.

Portable pumps and marine manifolds can also be deployed to provide firewater for the intervention efforts. This equipment will have to be flown in from the USA or sourced in the local market. Mobilization and rig up takes time. While this is underway the situation can worsen (structural damage, wellhead leaks, etc.). This pumping equipment and specially designed marine manifolds will be used for the purpose of applying firewater for prevention of subsequent damage and to cover the intervention efforts. If the primary support vessel has no firefighting capabilities, these pumps can be used exclusively. If other firefighting capabilities are available, they can be used in conjunction with the onboard pumps.

10.5.3 Moving Onto the Structure

Once sufficient working space is made an available on the structure, operations will be undertaken on the structure. The initial and supporting approaches with the MSV or crane barge will generally be determined by wind and tide direction.

Water monitors will be placed at the working area for more precise water application and protection of the crews and equipment. All operations near the wellhead must be done with a protective and/or cooling water spray cover. In some instances, portable cranes will be assembled on the deck of the structure. This will in turn be used for further debris removal, precise equipment placement and eventually for capping the well. In previous operations it has been possible to place a large tracked crane (80 ton) onto the deck of the well platform.



10.5.4 Gaining Wellhead Access

With operations established on the structure, final debris removal can begin which will allow wellhead access. This may require more cutting which can be done by one of the methods previously mentioned. If the well is on fire, all heated metal debris must be removed before the fire can be extinguished. A Venturi tube may be placed over the well flow to raise the ignition point and consolidate the flow. This will allow better access to the wellhead and provide a means to cool the surrounding structural steel components. Fires which cause major structural damage sometimes require extensive fabrication projects to re-build a working platform around the wellhead.

10.5.5 Extinguishing the Fire

Once clear access to the wellhead has been established, efforts will be made to configure the flow into a single vertical stream (if not so already). Many fires can be extinguished using water alone. Unless obviously unsuitable, this technique will be attempted first. The Venturi tube may be used in conjunction with the water application to improve the chances of success. If these attempts fail, explosives may be used to extinguish the fire (this is a rare occurrence in offshore operations however). Unless major structural damage is imminent the fire may be left burning until all preparations have been made for capping. This is done as a pollution control measure.

10.5.6 Wellhead, Tree and BOP Removal

With the fire either extinguished or directed through a Venture tube, closer inspection of the wellhead equipment can be made. This inspection will determine whether the existing equipment can be used to attach capping devices or if all or part of it will need to be removed. If nothing can be salvaged, the entire wellhead and all casing strings can be cut off. More detail can be found in Appendix b: Capping Operations.

10.5.7 Control Operations

Control operations usually fall into one of two general categories; shut-in or divert. If for some reason the well cannot be shut-in, it is common practice to divert the well and utilize a snubbing unit to either fish the tubing/drillpipe or to snub in a kill work string (e.g. place a tubing string on bottom for kill operations).

Depending on the severity of damage, extensive structural repair may be necessary before this type of work can proceed. If the well is to be diverted, flow lines and choke manifolds can be set in place allowing safe operations for construction while the well is on diversion.

There are infinite scenarios for kill operations so detail is not possible in this section. Kill operations will fall into board categories as follows;

- Bullhead after shut in.
- Dynamic kill through a work string.
- Circulate out after shut-in.

The circumstances of the event will guide the intervention team to the solution that best fits the conditions at hand. Much work may be needed to be in a position to kill the well. Careful evaluation of the integrity of the wellhead equipment on the well and the downhole equipment is a must. It is often the case that judgment is the only means to guide the kill operation. A general rule for kill operations is that the stresses induced in the kill should be kept to a minimum if there are any doubts with the pressure control equipment on or in the well.

Auxiliary vessels such as pump boats and fluid handling vessels may be required if the structure will not support or accommodate such equipment. If snubbing equipment or other wellhead



supported equipment of significant weight is to be utilized, additional fabrication may be necessary to insure structural integrity.

10.5.8 Support: MSV, Goods and Material Services

PRIMARY SUPPORT VESSEL: The primary support vessel is the platform from which the intervention effort will be directed. Conventionally moored derrick/pipelay barges are generally the vessel of choice for primary support. This type vessel possesses several features that are beneficial to the overall success of the project.

These barges are available with adequate open deck space to support even the most complex projects. Simultaneous projects such as fabrication, modifications and repairs can all be undertaken on deck. This significantly reduces the logistics of monitoring and supervision of these tasks.

Most derrick/pipelay barges are equipped with "jet" pumps mounted below deck. These pumps, normally used for pipe laying operations, are typically rated at 3,000-5,000 GPM @ 400-600 psi. Some barges have modifications that allow these pumps to be used for firefighting purposes. If not, the modifications must be made quickly. Where elevated structures are involved, these pumps can be used to supply water to other pumps mounted on the structure itself

The cranes on these type vessels are essential for debris removal and equipment/personnel movement to and from the structure. It is not unusual for crane lifting capabilities to far exceed actual needs. The heaviest lifts likely to be encountered are the removal of a complete drilling package from the platform. However, barges with lifting capabilities of 500 to 700 tons are sometimes required to ensure adequate boom length and deck space. A 300' boom length may be required to reach the uppermost portions of the structure while allowing a safe horizontal offset distance. A typical crane barge with a 300' boom offset 150' from the structure is only capable of lifting approximately 25% of its maximum rating to a height of 240'. Barge with larger dimensions also provide added stability which will allow work to proceed during moderately rough seas.

The additional expense of the larger barge is justified given the limited availability of this type vessel. If a smaller barge is contracted and conditions develop that make it inadequate, a larger vessel may not be immediately available. These are obviously very undesirable circumstances. Another benefit of the moored barge is its ability to be removed from proximity to the well in an emergency. This is often necessary due to changing well or weather conditions. Adequate towing capabilities (tugs) should be at hand to assist if needed. The derrick/pipelay barge should be mobilized to the location immediately. Firewater pumps and accessory equipment can be mobilized on a utility boat if required. Once on location, anchors can be set for the barge, the equipment can be off loaded from the utility boat and assembled prior to moving close to the structure.

SECONDARY VESSELS: In addition to the primary support vessel and pollution containment vessels, at least two crew boats and one utility (work) boat will be needed.

FABRICATION PERSONNEL AND EQUIPMENT: A minimum of two certified welders will be needed for various fabrication projects. Each should be fully supplied with necessary equipment such as welding machines, cutting torches, grinders, chipping hammers, wire brushes, etc. An adequate supply of safety equipment ordinarily used during fabrication projects such as goggles and face shields will be required.

ROUSTABOUTS: A roustabout crew will be needed for various tasks such as fabrication and rig-up of pumps and lines. A crew consisting of one supervisor and five roustabouts should be contracted.

MATERIAL: A considerable amount of fabrication material will be needed for various tasks. The material in the following list will generally provide an adequate amount for the initial requirements:

- 200 sheets – 2' x 8' galvanized corrugated tin (10 gauge or thicker)



- 150 lb. of bailing wire (soft wire for attaching fire shields)
- 30 joints – 2-3/8" tubing (junk)
- 12 pieces (500 ft²) – expanded metal grating
- 750 ft – 2" x 2" x 1/4" angle iron
- 500 ft – 3" x 3" x 1/4" angle iron
- 2 sheets – 4' x 8' x 1/4" steel plate
- 1 sheet – 4' x 8' x 1" steel plate
- 500 feet – 1/2" softlay cable (6 x 36) with 50 clamps
- 500 feet – 3/4" softlay cable (6 x 36) with 50 clamps
- 500 feet – 1" softlay cable (6 x 36) with 50 clamps
- 500 feet – 1-1/8" softlay cable (6 x 36) with 50 clamps
- 250 feet – 1/2" cold rolled bar

AIR COMPRESSOR: Two 255 CFM, 125 psi air compressor each with 300 ft of 2" 200 psi WP hose and spare end connections. These will be required to supply air for starting pumps and operating other pneumatic tools later in the project. Available through local specialty rental companies or may be available on the primary support vessel.

LIGHT TOWERS: Self-contained diesel powered light towers should be ordered to facilitate fabrication projects which may extend into the night, available from specialty rental companies. Primary support vessel may have adequate lighting.

ABRASIVE CUTTERS: Ultra-high pressure (30,000 + psi) cutters which use abrasive material such as frac sand, slag or crushed garnet. Used for debris wellhead and casing cutting in explosive atmospheres, available from Halliburton (Duncan, OK).

LATHE CUTTERS: Portable lathe type dye cutters may be required for circumferential cuts on casing strings.

EXPLOSIVES: Explosives may be necessary for debris removal and possibly for extinguishing the fire. NOTE: Since Abrasive Jet Cutters have been introduced explosives have been rarely used, therefore this is mentioned as a contingency only.

TRASH PUMPS: Portable air operated diaphragm type pumps may be needed for various fluid transfer tasks on the structure. Small pumps such as Wilden 3" are preferred since they provide the necessary mobility, available from specialty rental tool companies.

PORTABLE CRANES: it may become necessary to install a portable crane on the structure for capping and/or debris removal, available through various marine crane rental companies.

PNEUMATIC WINCHES: Large pneumatic winches, or "air tuggers", may be needed for capping and/or debris removal, available through specialty rental companies.

PNEUMATIC TOOLS: Impact wrenches, drills, grinders, pneumatic hacksaws along with hoses, sockets, bits and various other accessory pieces. These are available from most oilfield supply outlets.

HYDRAULIC TOOLS: Torque wrenches, nut splitters and portable power jacks. These are available from pressure testing companies and specialty rental companies.

SURFACE EQUIPEMNT: BOPS's, chokes/manifolds, closing units, chocksan lines etc. Available from oilfield rental tool companies.



10.5.9 Personnel Safety and Medical Services

The highest possible standards must be maintained with regard to personnel safety at all times. The well control intervention team will constantly strive to insure the safest possible working environment based on their previous experience with similar situations. However, risks will inevitably be involved with some operations. The well control team must work with TOTAL to properly manage and minimize these risks.

EMERGENCY MEDICAL EQUIPMENT: There should be trained medical personnel on location with equipment to treat trauma. Their expertise should cover burn treatment in addition to typical oil-field related injuries. Certified EMT, personnel are available through some oil-field safety companies such as CAMCO, SABER, etc.

MEDIVAC SERVICES: A medical evacuation helicopter should be on alert at all times to transport seriously injured personnel to near-by medical facilities for treatment. This service should be able to provide advanced life support during transit.

10.5.10 Communications

Efficient communication is essential to the success and safety of the project. A central dispatching system must be arranged to control the movement of equipment and personnel (existing system or installed after the incident occurs). This is best handled by a central base station operation where a radio operator continually monitors and dispatches necessary services in conjunction with the TOTAL project control procedures and purchasing specifications.

An independent communication link should be established between the location and the coordinating TOTAL office. Voice and data transfer capabilities will be necessary.

On-site communications are vital. Portable radios should be provided with a dedicated frequency to be used by the personnel at the location.

10.5.11 Fabrication

If a major fabrication project becomes necessary, the most expedient method may be to have it undertaken onshore. In some cases the offshore construction barge or MSV may be able to handle the job. An evaluation should be conducted to assess the need for major fabrication projects as soon as feasible and make the decision to fabrication onshore or offshore. Regardless of the choice, a competent fabrication shop should be contracted to begin the projects(s) immediately.

10.5.12 Machine Shop Services

There may be occasion to construct or repair precision components of various pieces of equipment used in the well control effort. It is recommended that a full service machine shop be available on a 24 hour basis during the project.

10.5.13 General Support

There should be a pool of resources that cover labor and transportation as well as procurement and expediting to support the well control effort. One should not lose sight of the fact that, in the end, all costs will have to be accounted for and justified. Tracking of material and documentation of purchasing will be essential tasks that can best be done at the time of procurement rather than after the fact.

10.5.14 Weather Monitoring

A recognized weather reporting/forecasting service should be employed. Daily weather reports should be made available to the TOTAL coordinating office and the personnel on location. Prior knowledge of impending weather changes can be a valuable tool for operational planning and safety.

10.5.15 Personnel Quartering

If adequate facilities are not present on the primary support vessel, arrangements will have to be made for housing and feeding of the personnel on location. A 24 hour galley may be necessary as fabrication and repair projects will likely be on-going around the clock. Laundry services will be needed for personnel staying on location. It is expected that these needs will be met by contracting a "floatel" or by using adjacent TOTAL facilities.

10.5.16 Firefighting Equipment

The major well control vendors have an inventory of specialized tools and equipment ready for immediate mobilization 24 hours a day. The following is a partial listing including a brief description;

- Fire pumps – Driven by diesel engines with centrifugal high volume low pressure firewater pump. (Example: Detroit Diesel 8V-91, 540 HP turbo charged engine with centrifugal pump delivering 4 to 5,000 GPM @ 200 psi) Each pump is mounted on an oilfield skid with protective roll cage and single lift attachment point, forklift attachment and loading hitch for rolling tailboard transport.
- Suction manifolds, suction and discharge hoses.
- Marine manifold for installation on marine vessel deck. The main components of the marine manifold are.
 - 1 ea., 10" x 20' steel fire monitor manifold w/ 4 ea. 4" flanged outlets, 1 ea., 10" flanged inlet, 4 ea. 4" butterfly valves, 4 ea. 4" Fig. 100 hammer unions.
 - 3 ea., 10" x 21' flanged supply line sections
 - 1 ea., 10" x 16' flanged supply line section
 - 1 ea., 10" x 6" 90° flanged elbow
 - 4 ea., 6" x 4' steel pipe extensions w/90 ° ells for use with suction hoses
 - 4 ea., 1000 GPM water cannons
- Fire monitors: 2,000 to 6,000 GPM.
- Casing clamps: for use in various capping procedures.
- Venturi tube: to consolidate and raise the flow and/or ignition point.
- Portable toolhouse – containing complete set of hand tools from ¼" end wrench to 48" pipe wrench for maintenance and repair. Complete set of hammer wrenches and brass hammers.
- Portable Lathe Type Cutters – Used for making circumferential cuts on casing strings.
- Explosives – All necessary equipment for demolition. A fully-licensed explosives expert will be required.
- Nomex Protective Clothing – For use by personnel working in proximity to the combustible flow or fire.

- Communications – Hand held radios for use by personnel on location
- Foam/Dispersant Application – For fire extinguishing or protection

10.6 CAPPING OPERATIONS

Capping operations are an integral part of most blowout intervention projects. In many instances, capping of the blowout well is the primary objective, the first major step in regaining control of the well.

The term "capping" is sometimes loosely used to refer to the whole process of surface intervention. The more precise definition, used here, is the placement of a competent pressure control device onto the blowout well under flowing conditions. Once the new control device (BOP, valve, etc.) is positioned over the well, there must be a means of attaching the device so that pressure integrity can be regained.

Regardless of its components, the control device is typically referred to as the capping stack or capping assembly. The magnitude of the pressure which the control device will be expected to withstand is the Maximum Anticipated Surface Pressure (MASP). For capping operations, the MASP is the maximum shut-in wellhead pressure plus externally applied pressure (e.g., pressures exerted while bullheading) multiplied by a safety factor (e.g., 1.25). The MASP with appropriate safety factor should be compared to the working pressure of the equipment. Temperature can be a consideration, as the BOP may need to be de-rated for the flowing wellhead temperature. This is especially true for HTHP wells. Capping operations also include preparing the wellhead for placement of the capping stack. This sometimes involves removal of part or all of the existing wellhead/BOP stack.

Important factors to consider in planning a capping operation include:

- Forces exerted on the capping stack as it is brought into the flow.
- Best method to insure full control of the movement of the capping stack when it enters the flow (prevention of turning and swinging).
- Measures to minimize the potential for ignition during the capping operation and contingencies for ignition if it does occur.
- Through bore size (ID) of the capping stack sufficient to allow subsequent work.
- Functions required of the capping stack (e.g., outlets needed for diverting the flow, pumping into the well, pressure monitoring and snubbing operations).
- Best attachment method for securing the capping stack to the well.
- Pressure and temperature ratings required to control the well throughout all phases of the well control operation.
- Forces exerted on the capping stack during the post capping operations such as snubbing and bullheading.

Proper planning of a capping operation must take into account the mass flow rate, combustible nature of the flow, wellbore geometry and operations to be undertaken in the ensuring post-capping phase of the project. The methods used for capping can generally be divided into three techniques:

- Capping to a flange.
- Capping to a stub by first installing a wellhead.
- Capping to a stub by swallowing the stub.

This chapter provides an overview of the steps necessary to safely accomplish capping operations using these three techniques.

10.6.1 GAINING ACCESS WITH THE ACV

Before the actual capping process can begin, well access is necessary. Direct access is usually denied because of structural damage to the drilling structure or platform. Debris, which may include melted masses of metal, must be removed before the intervention at the wellhead can begin. The All-Purpose Capping Vehicle (ACV) was developed for the purposes of working on blowing wells that can also be on fire. ACV applications include:

- Removing debris using hooks and rakes.
- Conveying special tools, such as abrasive jet cutters, Venturi tubes and stingers.
- Placing explosives at a "safe" distance for severing or extinguishing the fire.
- Hoisting and stabbing-on capping assemblies.
-

Figures F.1 and F.2 illustrate the two main types of ACV's Figure F.3 shows end attachments often used in well control operations.

In the early years of the well control business, Athey wagons were employed to drag damaged equipment from the well. They were generally used to remove debris and only rarely to convey tools to the wellhead. The name 'Athey' is in fact a misnomer, as it actually refers to the leading manufacturer of a certain type of steel track used for rig moves, or for moving heavy lifts in rough terrain, though the older name is still commonly used by capping companies. All-Purpose Capping Vehicle or ACV better describes the capabilities of the modern vehicles.

There are two basic versions of the ACV: conventional and hydraulic. The conventional unit relies on the power of a bulldozer and its tail winch to move and position the boom. Figure F.1 shows the conventional ACV hooked up to a bulldozer. The tail winch articulates the boom while the dozer is used to position the wagon.

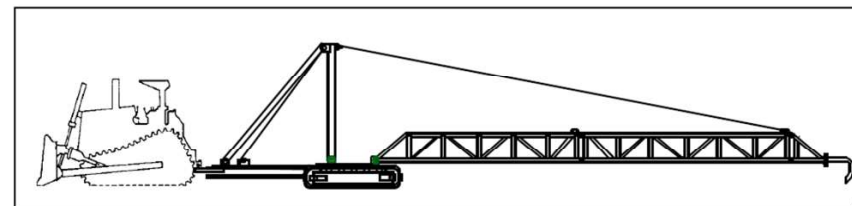


Figure F.1 Conventional ACV with End Hook Attachment

The hydraulic version of the ACV was developed primarily for the purpose of stabbing-on BOP and conveying tools that require precise positioning, such as the abrasive jet cutter. In these applications, hydraulic winches provide fine control of the boom articulation. Wild Well Control, Inc. has developed a hydraulic ACV that is secured by a bulldozer, which provides movement, hydraulic winches to control the boom angle and a set of winches at the front of the vehicle for pulling or snubbing on BOPs. One drawback of the hydraulic ACV is the requirement of a power pack to operate the hydraulic winches, and this increases the overall air shipping weight and volume. However, all components break down into small lifts that will fit on almost all commercial cargo planes. Figure F.2 illustrates the hydraulic model of the ACV equipped for a stab-on manoeuvre.

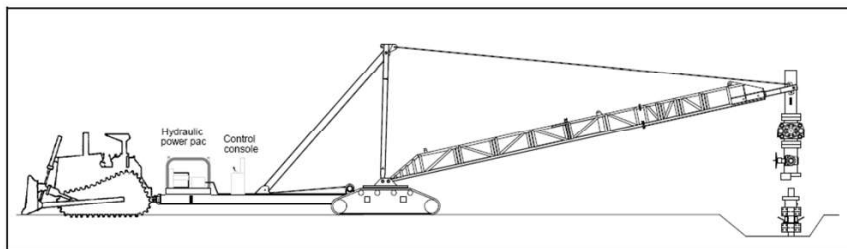


Figure F.2 Hydraulic ACV Stabbing-on a BOP

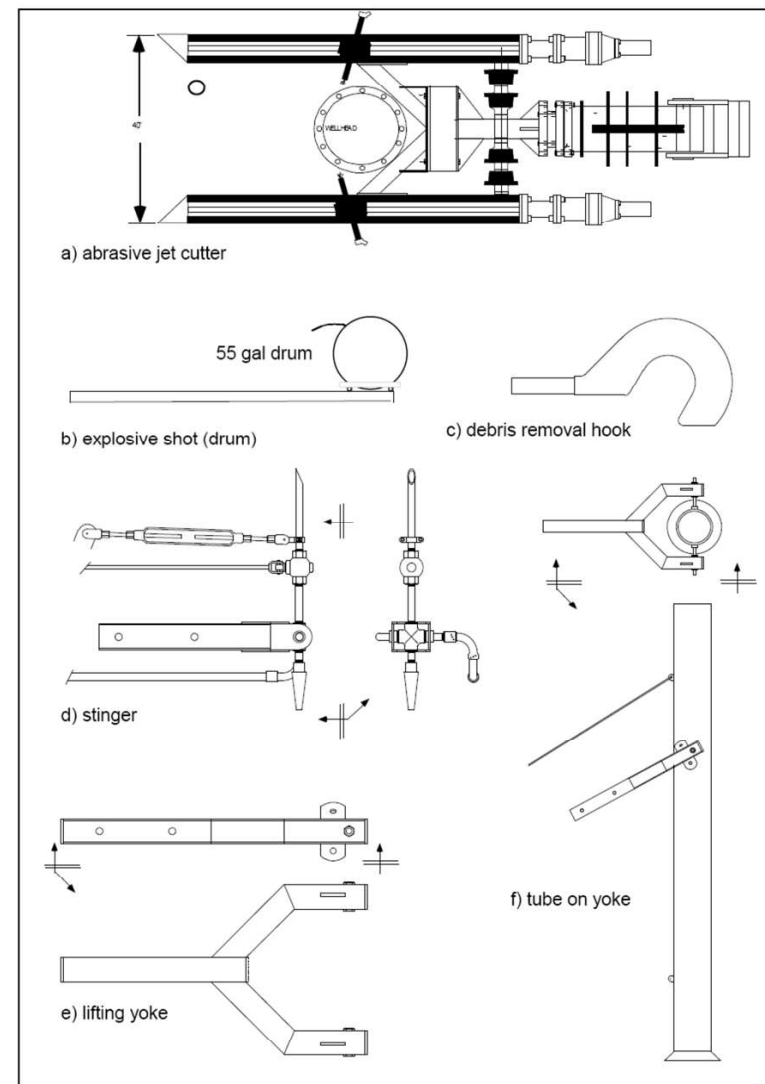


Figure F.3 Typical ACV End Attachments

10.6.2 Wellhead and BOP Removal

With the fire either extinguished or directed through a Venturi tube, close inspection of the wellhead equipment can be made and work can be performed at the wellhead. The inspection will determine whether the existing equipment can be used to attach capping devices or if all or part of it will need to be removed.

Caution! Reusing wellhead components that have been involved in a blowout can be hazardous and must be thoroughly evaluated. If nothing can be salvaged, the entire wellhead and all casing strings will need to be cut off and new equipment installed.

Wellhead or BOP components must be removed when they have suffered structural damage. Falling debris can cause mechanical damage and fire can weaken the integrity of most elastomer seals.

A typical technique for removing wellhead or BOP components is to install clamps on the flange to allow the removal of all bolts. A crane is attached to the component and snub lines are installed through the bolt holes. With the snub lines tight, the clamps are removed and the component can be taken off in a controlled manner. Other removal methods have included explosives, cables, and even hand-operated hacksaws. Some operators have resorted to tearing the wellhead off with brute force, which often caused additional damage and prolonged capping work to repair the casing.

Explosives have proved to be a highly precise and reliable method for removing wellhead equipment or sections of casing at the surface. This technology requires very specialized expertise and highly experienced personnel.

Shaped charges can be constructed to accomplish a variety of tasks, from severing the entire wellhead to removing casing valves or strings. If properly applied, shaped charges can remove an outer string of casing without damaging the next inner string. Figure F.4 shows a typical shaped charge configuration with a focused bias for removing a single outer casing string.

By contrast, the cable method is a crude type of friction cut. It is now considered outdated technology. Wire rope or cable is wrapped around the wellhead or casing and each end is connected to a swabbing unit. The cable is then dragged back and forth until it severs the casing. The cable method works, but often takes several days. Depending on the number of casing strings and the presence of cement, the job could take from two to five days of continuous cutting. There are other disadvantages to this method. The cut is difficult to re-enter if the cable is pulled out of the groove. Cable replacement is often necessary due to wear, overheating, breakage or when the operation is shut down for darkness. Cable cutting can cause the casing to become egged, further hindering the capping operation.

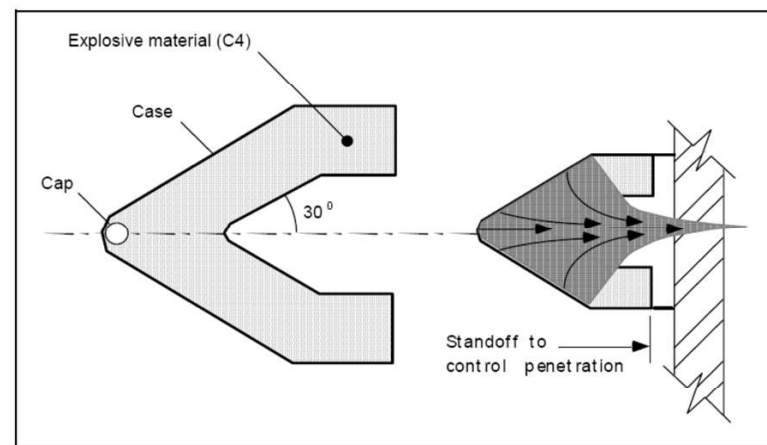


Figure F.4 Shaped Charge Diagram

The Kuwait oil fires proved the perfect testing ground for the abrasive jet cutter, a newer and more efficient cutting method. This equipment performed well in the removal of damaged wellhead components and trees. It was one of the most important innovations responsible for increasing the speed of capping operations in Kuwait. Two types of cutting services were used there: the Hydro-Jet (by Halliburton) and the Ultra-High-Pressure (UHP) abrasive particles to erode away metal and cement, but they are very different tools.

The UHP equipment is an ultra-high pressure, trailer mounted, self-contained system capable of quick mobilization and easy rig up. Rig-up consists of attaching a split-type track with hydraulic advancing tractor to the wellhead above or below the area to be cut off. This is typically done by two men without a crane. The tractor and nozzle are then positioned on the track and attached to the water, abrasive and hydraulic lines.

A high pressure, low volume stream of water and abrasive slurry is pumped through the jet at the area to be cut, and a circumferential cut is performed. The device works very much like an automatic track torch used to bevel pipe. The water leaves the jet nozzle with a pressure in excess of 30,000 psi. Generally, the nozzle used is a 0.75 mm diameter, man-made ruby. The calculated nozzle velocity at a typical pump rate of 4 gpm is 2,007 ft/sec (roughly equivalent to Mach 2⁺). The abrasive material is conveyed to the jet body through a separate line with compressed air. The abrasive enters the jet through a siphon port by Venturi effect and is discharged through the nozzle. Excess abrasive returns to the hopper through a hose. In Kuwait, the abrasive used was granulated garnet with a hardness of 7.5 as compared to steel at 6.0.

The jet can be configured in different ways to meet specific cutting requirements. In several instances in Kuwait, it made circular cuts through as many as seven cemented strings of casing, with one or more blowing, to remove a damaged wellhead. The average time spent on this type of circular cut was between one and two hours with many done in less than one hour.

To cut off a wellhead completely, the jet nozzle is pointed directly at the casing, perpendicular to its axis. The jet circumnavigates the casing on the track, making a complete 360 degree cut. The jet stream usually penetrates 15 to 18 inches. Depth of penetration is highly dependent on the tracking speed.

Sometimes it is necessary to leave the inner string or production casing intact and peel back the outside strings. This is done by setting the jet at an angle where the abrasive stream never penetrates deeper than the thickness of the outer string. In either case, the cut is remotely controlled by the operator and no personnel are required close to the wellhead during the cutting operation.

The UHP jet cutter is not limited to circular casing cuts. For example, the track can be attached to the wellhead, allowing cuts to be made under damaged valves or between flanges. One unique application of the tool is for cutting bolts and other small diameter sections. In this case, the jet cutter is mounted on a tripod stand (see Figure F.5) and the operator can cut the nuts off the top or bottom of the flange in short order. The time required to cut a single API 11" 3M stud ranges from 45 seconds to 8 minutes. Sometimes the bolts can even be cut between the flanges, depending on the severity of the damage.

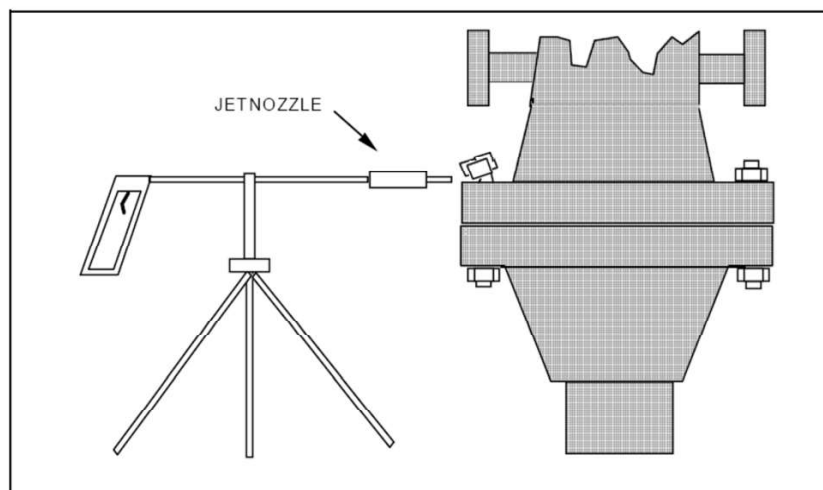
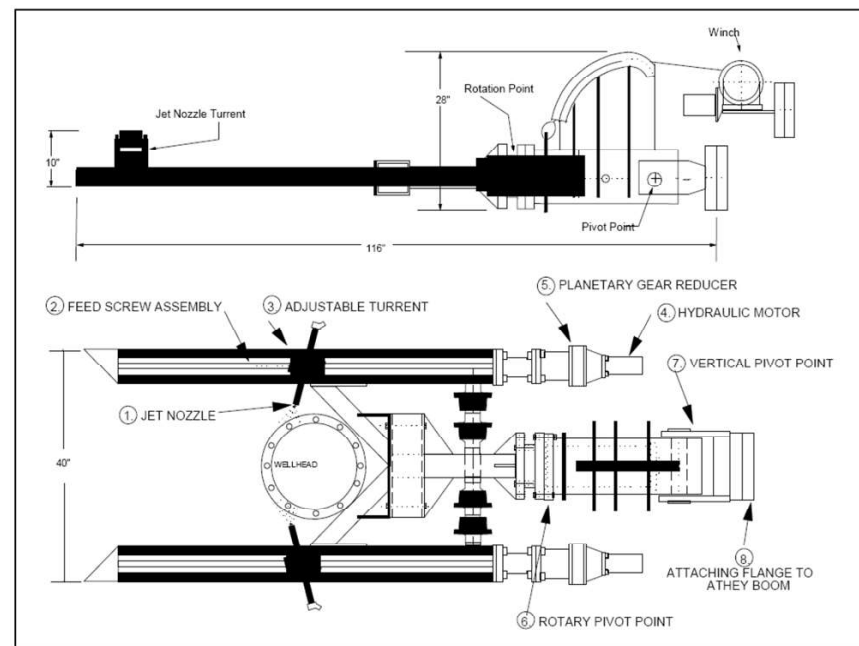


Figure F.5 Bolt Cutting with a Hand-Held Gun and Tripod

The ultra-high pressure cutting tool does have some limitations. The operator must physically attach the tractor band to the wellhead or casing, and when there is lateral flow this is virtually impossible to do. The cut is jagged and often irregular, perhaps because of the light construction of the tracking frame. But despite these minor limitations, the UHP jet cutter is a valuable asset to the capping operation.

Halliburton's HYDRA-JET cutter was adapted for use in Kuwait by the creation of a specialized carrier, allowing it to be conveyed to the wellhead using a conventional ACV boom. Two different carriers were employed in Kuwait. One was a vertical cutter with a single nozzle. The other was a horizontal carrier with a U-shaped yoke and two opposing jet nozzles (see Figure F.6). In both versions, a small hydraulic motor drives long worm screws to advance the cutters along the length of the yoke. To make the cut, a slurry of gelled water and 1ppg sand is pumped at 150 gpm to each 3/16" nozzle, a much higher flow-rate than the UHP device, and at a lower pressure of approximately 11,000 psi. The abrasive stream of high pressure slurry erodes away the casing or wellhead, tracking laterally much like a hacksaw blade passing through a piece of pipe.

The jet cutter requires considerably more rig-up time and equipment than the UHP unit. However, the jet cutter can cut off a wellhead that is on fire or has limited access due to lateral flow, because it can be conveyed at the end of the ACV boom. It can be cooled and shielded from the fire by a water spray. Its hydraulic control lines are protected in an arrangement that resembles a tube-and-shell heat exchanger. The lines run inside the tube and water is circulated around them to cool the system.



Halliburton Horizontal Cutter With Yoke Attachment

(Courtesy of Halliburton Energy Services, Duncan OK)

Figure F.6 Halliburton Horizontal Cutter with Yoke Attachment



Table F.1 Comparison of High-Pressure (Hydro-Jet) and Ultra-High Pressure (UHP) Cutting Techniques

	Ultra-High-Pressure	Hydra-Jet Cutter
Pump Pressure	30,000 psi	10-12,000 psi
Discharge Rate	3 - 4 gpm	84 gpm – one nozzle 170 gpm – two nozzles
Nozzles	0.5 to 0.7 mm man-made ruby	3/16" tungsten carbide
Pump Unit	1 – single unit Self-contained	1 hydraulic hose/power unit 2 cement/frac trucks
Cutting Track	Circular ± 200 lbs	U-yoke and vertical types ± 1,800 lbs
Rig-Up	No crane required attaches by hand with screw clamps ±1 hr.	Crane and AVC boom required boom refit (if required) ± 6 hrs
Well Conditions	Fire extinguished personnel access required.	Well can be on fire no close personnel access required
Fire Protection	None available	Shielded and water cooled
Support Protection	50 bbls distilled water truck with filter	1 sand bulk truck 2 gelled water trucks
Feed Water	Drinking quality with tank	Semi-clean/brackish
Consumables	Crushed garnet	40 mesh frac sand, 1 ppg
Personnel	4	± 6

The vertical cutter has a single arm jet holder. It can be used to cut off wing valves or flowlines when necessary. The vertical cutting time of 50-80 minutes is comparable to the UHP, if rig-up time is not considered. In either vertical or horizontal position, the finished cut is clean and smooth.

Using the HYDRA-JET cutter does create some special logistical considerations. The higher cutting-fluid volume requires the use of tank trucks (or frac tanks offshore) to supply the fluid, and a bulk truck (or skid) to supply the sand. The high pressure, high volume fluid discharges also require more horsepower, resulting in a large equipment spread. On a small location extra dirt work may be required to accommodate all the equipment. The ACV boom must be retrofit to accommodate the carrier (unless special provisions are already built-in). The rig-up time of several hours should be taken into consideration for daylight-only operations. Based on the Kuwait experience, Halliburton has made substantial improvements to the jet cutter, reducing the amount of equipment required.

Even with their individual disadvantages, these tools far outperform previous methods for removing damaged components on blowing or burning wells. They represent a significant advance in wild well control technique.

Both cutters worked well in Kuwait and, between the two, almost any conceivable cutting job can be accomplished. It would be unfair to say that one was better than the other because both fit into useful niches. Table F.1 shows a comparison of the two cutters.

Following the cut-off, circumferential cuts must be made on the casing strings prior to capping. These cuts can be made with an abrasive jet cutter or a portable lathe die cutter. The lathe cutter utilizes a track, air or hydraulic motor and a hardened cutting blade similar to those used on commercial lathes. The lathe cutter can be split and wrapped around the casing so it can be mounted without entering the flow. The resulting cuts have beveled machine-quality edges. The casing strings are cut at different lengths to expose an adequate amount of the innermost string for capping purposes. If necessary, these cuts can be made with the well on fire.



10.6.3 Capping to a Flange

In large violent flows of high velocity, the snub-on technique is recommended for installation of a capping stack to an existing flange. This is not a hard and fast rule, but generally the idea is to control the movement of the capping stack along its three axes by the use of hoist, tag and snub lines. This method, illustrated in Figure F.7, involves the following steps:

- Rig up a capping assembly with a mating flange, and proper pressure, temperature and service ratings. Track weld the ring gasket to the bottom of the capping assembly flange.
- Hold a final safety and coordination meeting to insure that all personnel understand the safety procedures to be followed and the operational plans, including the contingency plan for a flash fire or explosion.
- Snub the capping assembly into the flow. Center and lower the capping assembly and mate the flanges.
- Install bolts and tighten to energize ring gasket seal.
- Connect hydraulic lines between the closing unit and capping assembly.
- Install diverter lines and kill lines as necessary, then continue with the chosen course of action, e.g., pump to kill, divert, or rig-up to snub.

Similar procedures are used whether the capping assembly consists of a valve arrangement or a BOP stack. Torque wrenches should be available to speed the installation and insure a proper seal since pressure testing is often impossible.

10.6.4 Capping to a Stub by Installing a Wellhead

This procedure is an option when the entire wellhead has been removed, leaving only a casing stub. After cutting back the outer strings of casing to expose the capping string, a standard slip-on weld type head is modified by adding pad eyes for attaching the snub lines. For ease of installation, this wellhead should be at least one size larger than the casing stub to be swallowed, for example, a 9-5/8" head would be used to cap 7" casing.

As an option, a plate can be tack welded onto the side of the head to deflect the flow and improve visibility as the spool is placed into the flow over the casing stub. This plate will have to be removed before installation of the casing clamps. Snatch blocks are secured to the base of the casing with a bolt-on clamp (see Figure F.8). Cables are threaded through the snatch blocks and attached to the head to facilitate the snub-on operation.

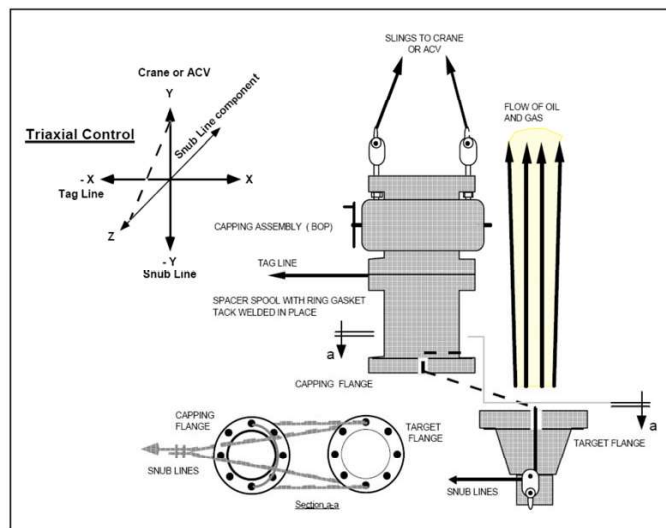


Figure F.7 Capping to a Flange via Snub lines

Once the head has been positioned over the casing stub, the blocks and snub line are removed. A second clamp is installed, but not tightened, between the existing clamp and the head. Hydraulic jacks are positioned between the two clamps (bottom clamp is secure, top clamp is loose). A standard set of split type casing slips are placed in the bowl and engaged by using the hydraulic jacks. After the slips are in place and the pack-off is energized, the top clamp is secured under the head to hold it in place when the hydraulic jacks are released. The sequence is illustrated in Figure F.9

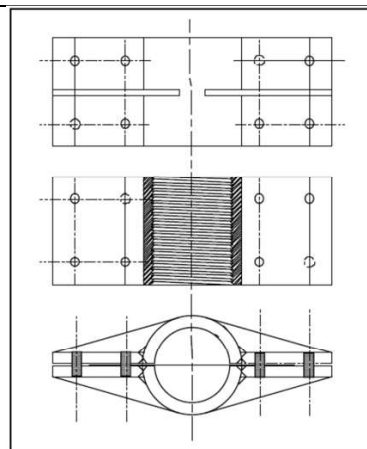


Figure F.8 Casing Clamp
(Courtesy of Blowout Tools, Inc., Lafayette, LA)

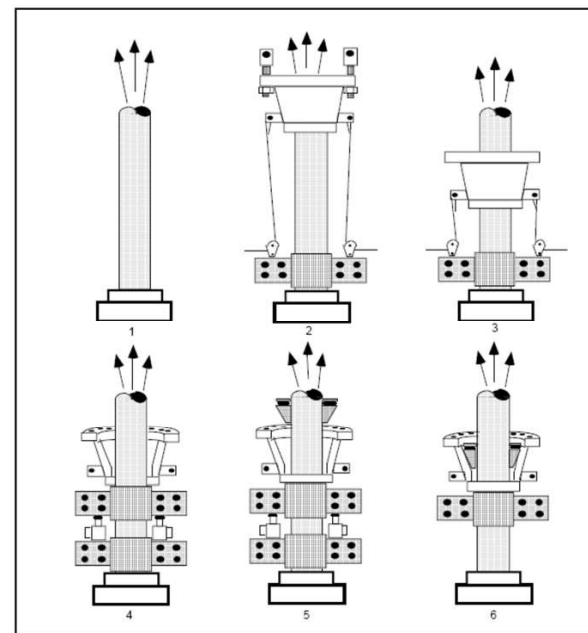


Figure F.9 Emergency Wellhead Installation

To calculate the jacking force required to fix the wellhead onto the casing stub, all subsequent operations should be considered, including:

- Rig deal loads (e.g. BOPE, snubbing equipment)
- Dynamic loading:
 - Pull from snubbing jack
 - Running casing
 - Applied pressure (e.g., shut-in bullheading)

A minimum of two calculations should be made based on the worst case scenarios for forces acting in the upward and downward directions, as illustrated in Example F.1

Example

Given:

SIWHP = 6500 psi

Casing Capped – 7-5/8" in., 47.1 lbs/ft, N-80 (0.8 F_y = 880 kbf, 80% Burst = 8,392 psi)

Snubbing jack weight – 22,000 lbs

BOPE Weight – 40,000 lbs

Snubbing String – 3-1/2" in. 15.5 lbs/ft S-135 DP (80% F_y = 464.8 kbf)

Measured Total Depth (MD) – 15,000 ft

Determine: a) Maximum upward & b) downward forces on wellhead (Fig F.10)

F_{ew}=Equipment dead weight (weight of snubbing jack, BOPs, etc.)

F_p=Pipe weight [ppf * pipe depth (ft)]

F_{p-a}=Pressure area effect (internal pressure* cross-sectional area casing I.D)

Worst Case – Upward Forces:

Bullheading at 80% burst pressure of casing with no pipe in hole.

$$\Sigma F = F_p + F_{ew} + F_t$$

$$F_p = 0$$

$$F_{ew} = 62,000 \text{ lbf}$$

$$F_{tw} = \frac{\pi (6.375^2)}{4} (8,392 \text{ psi}) \Rightarrow +267,865 \text{ lbf}$$

Therefore:

$$\Sigma F = F_p + F_{ew} + F_t$$

$$\Sigma F = 0 - 62,000 + 267,865$$

$$\Sigma F = 205,865 \text{ lb}_t \uparrow$$

Worst Case – Downward Forces:

Pipe on bottom (stuck) with wellhead pressure @ 0 psi. Pull 80% F_y of work string.

$$F_p = 0.8 F_y \text{ work string} = -464,800 \text{ lbf}$$

$$F_{ew} = 62,000 \text{ lbf}$$

$$F_t = 0 \text{ lbf}$$

Therefore:

$$\Sigma F = F_p + F_{ew} + F_t$$

$$\Sigma F = 464,800 - 62,000 + 0$$

$$\Sigma F = -526,800 \text{ lb}_f \downarrow$$

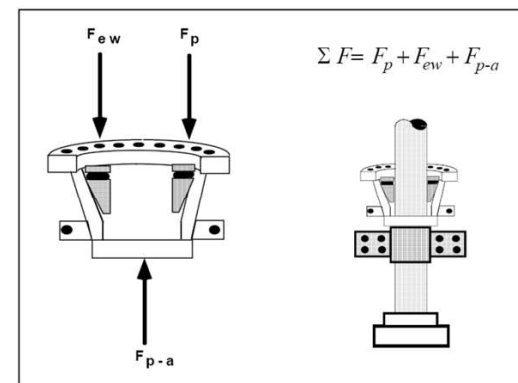


Figure F.10 Diagram of Wellhead Forces

Note that the net upward forces are transferred to the casing slips. These forces should not be allowed to exceed 80% of the casing tensile strength. Since the casing slips are incapable of imparting a downward force, all net downward forces are transferred to the casing via the casing clamp. Maximum unsupported bucking length associated with the worst case scenarios exceed 50% of the maximum tensile stress, bi-axial (axial and hoop stresses) calculations should be performed to evaluate the safety of the rig up.

10.6.5 Capping by Swallowing the Stub

Capping by swallowing the stub is an alternative when the entire wellhead has been removed. This procedure can also be used for capping drillpipe or tubing.

The typical capping assembly for this procedure (see Figure F.11) is a BOP stack. The stack is dressed out with (bottom to top):

- Slip rams
- Inverted pipe rams
- Drilling spool with one each manual and hydraulic valve on each outlet
- Blind rams

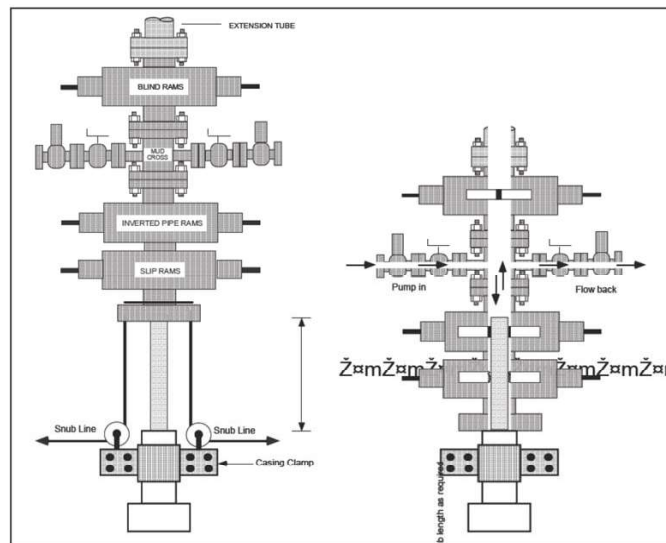


Figure F.11 Typical BOP Stack for Swallowing Casing Stub

Unlike pipe and blind rams, slip rams are not pressure sealing devices. They provide a mechanical grip only which is used to fix the BOP to the casing stub. Figure F.12 shows a diagram of a slip ram insert for a Cameron Type U preventer.

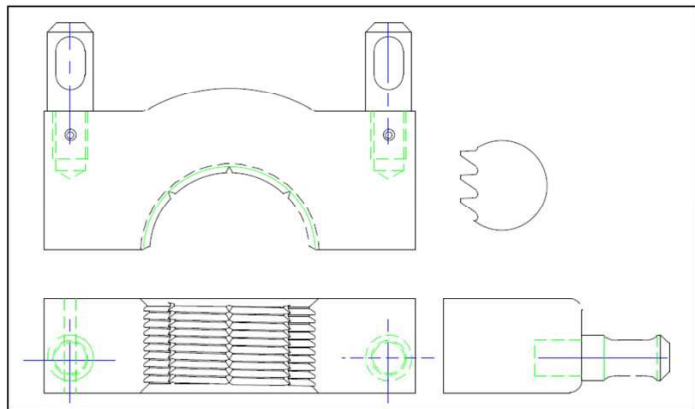


Figure F.12 Slip Ram Inserts (Courtesy of Blowout Tools, Inc. Lafayette, LA)

Once the proper amount of casing is exposed, a casing clamp is installed on the outer casing stub. This clamp is then used to connect the snatch blocks and the snub lines. The BOP stack is lifted with the crane and controlled with the snub and tag lines while being placed over the casing stub. With the BOP assembly safely over the casing stub, the hydraulic lines are connected from the closing unit. The rams are closed in the following sequence:

- Slip rams – to fix the BOP stack onto the casing stub. Note that the BOP must be laterally supported to prevent casing damage from bending forces.
- Inverted pipe rams – to contain the pressure exerted from the top.
- Blind rams – to shut-off the flow, or direct the flow through the side outlet valves for diverting.

The BOP stack can be stabilized with hydraulic jacks and casing clamps if further rig-up is required, such as snubbing or coiled tubing equipment.

10.6.6 Spin On Technique

Spinning a valve or BOP into a flow is a viable option for capping of a flow. The technique is illustrated in Fig F.13. The procedure is simple and has been in use since the 1930's. Very large flows can be handled this way in a safe and efficient manner.

Once feature is that this can be done and requires no special materials or fabrication. Valves and BOPs can be removed as well as installed using this method. As in any capping operation the potential for ignition cannot be eliminated, so firewater protection for the capping crews must be maintained during this and all capping manoeuvres. One drawback is the close proximity of the capping crew to the flow. This aspect must be carefully evaluated. The procedures for installation to an existing flange are as follows:

- Install a hinge bolt (one longer bolt flange).
- Install a lever arm to the capping assembly and sling the assembly for lifting.
- Lift and position the capping assembly onto the hinge bolt at 180 degrees (see 'a-a' of Figure B.13)
- Position crane hook at centerline of the flow/flange to be capped.
- Cover the work area with fire water.
- Manually spin the valve into the flow and align capping and mating flanges.
- Drop in bolts and torque up to effect seal.

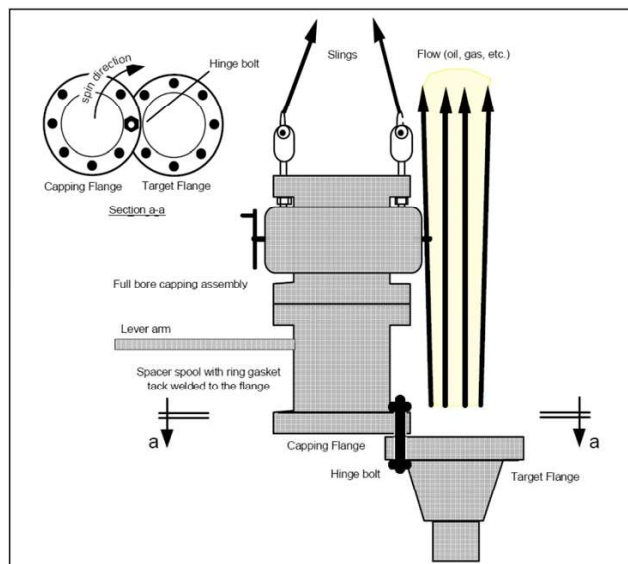


Figure F.13 Spin-on Technique

10.6.7 Forces Encountered during capping operations

The forces imparted on the capping assembly as it is brought into the flow stream can be substantial. A conservative approach is usually taken with regard to the size cables used for the snub lines. However it is sometimes useful to estimate the magnitude of the forces to be encountered. This is done by calculating the momentum flux through a control volume surface which is taken to be the area of the flow stream. This provides a conservative margin since only part of the flow should actually impact onto the capping assembly.

Equation

$$F_{mg} = \frac{S Q_g^2}{1.715 (10^{10}) Z D_c^2}$$

Where:

F_{mg} = momentum force of gas, lb force

S = gas specific gravity (Air = 1.0, natural gas use 0.6 to 0.7)

Q_g = volume rate of gas flow, scf/day

Z = average gas compressibility factor

D_c = diameter of flow (casing ID), inches

Equation F.2

$$F_{ml} = \frac{\rho Q_l^2}{2.6785 D_c^2}$$

Where:

F_{ml} = momentum force of the liquid, lbs force

ρ = fluid density, lbm/gal

Q = liquid flow rate, bbl/min

D_c = diameter of flow (casing ID), inches

Example

Given :

A gas flow rate = 50,000,000 scf/day (used to yield conservative result).

Casing size = 5-1/2 – in. O.D., 5.0-in. I.D.

Gas specific gravity = 0.7

Z factor = 0.95

Associated liquid of 28,000 bbls/day of 9.3 ppg salt water

$$F_{mg} = \frac{(0.7)(50,000,000)^2}{1.715 (10^{10})(0.95)(5^2)} \Rightarrow 4296.5 \text{ lbf}$$

Second, calculate liquid momentum:

$$F_{ml} = \frac{(9.3) \left(\frac{28000}{24 \times 60} \right)^2}{2.6785 (5)^2} \Rightarrow 52.5 \text{ lbf}$$

The total force possible will be 4296.6 + 52.5 = 4349 lbf or say 4500 lbf. Therefore the cables or boom must be able to withstand a live load force of about 4500 lbf. If a cable system is to be used a minimum safety factor of 4 should be used (4.0 is the preferred design safety factor recommended for this very critical component). Thus the design load will be 4 x 4500 or 18,000 lbs force.

10.6.8 Capping on Fire

Emphasis on environment and personnel safety has caused certain wells to be capped on fire. From an environmental viewpoint, leaving a well on fire can reduce the amount of pollution, provided the well is burning clean. One must realize that capping operations may take longer to complete if the well is left on fire throughout the entire operation. If the well is not burning cleanly then a judgment is needed to determine if less pollution will be caused if the fire is extinguished and thereby allow quicker capping operations.

Capping on fire is also justified if toxic gases are being produced, such as H_2S . Leaving the well on fire may be the solution to personnel hazards for the escaping gases. Regardless of whether the well is on fire or not, the work should proceed carefully taking necessary precautions for H_2S hazards while taking care to guard the intervention team from burns.

An ACV can be used to cap a well on fire. In this particular instance the main reason to leave the well on fire was to prevent pollution from running off into a creek. This creek fed directly into a

drinking water supply reservoir. For this reason it was imperative to avoid polluting the creek at all possible costs.

10.6.9 Stinging to Kill

The stinging operation is technique that can be used to kill a blowing well while it is on fire or simply blowing, provided certain well conditions prevail. Stinging to kill the well is the placement of a "stinger" in the throat of a blowing well in such a way that it functions as a temporary valve. The stinger has a hollow bore that will enable a kill fluid to be pumped into the well by bullheading. It may be the most expedient means to control the well provided wellhead and downhole conditions are favorable. In offshore operations, extra fabrication is sometimes necessary. Some means of placing the stinger at the wellhead will have to be fabricated based on the conditions of the well and structure. The conditions necessary for a successful stinging operations are:

- Shut-in wellhead pressure will be less than 1000 psi.
- Cross sectional flow area must also be fairly small (max 6.5" I.D.)
- There is an unobstructed access to the flow area.
- Ovality of the flow area must be less than 5%
- Downhole conditions are conducive for a bullhead kill.
- Pressure area effect must be less than 30,000 lbs force.

IF the SIWHP is greater than 1000 psi it may be difficulty to create a seal with bridging agents. Common bridging agents are hard rubber, gel, barite, nylon rope or other lost circulation material. These are mixed as a slurry and pumped ahead in a pill. They should be graded in size from 2 mm up to 20 mm (1/16" to 3/4"). Strips of rubber from tire inner tubes are an excellent bridging agent for stinging operations, however almost any type of lost circulation material will suffice. If the shut in pressure will produce more than 16 metric tons (35,200 lbs) of upward thrust from the pressure area effect, it may not be possible to provide rigging or tie downs that will prevent pump-out (ejection) of the stinger (which is assumed to be 99% round) is less than 5 mm (3/16 inch). If this gap is small the bridging agents can seal the leak, per the diagram shown in Figure F.14.

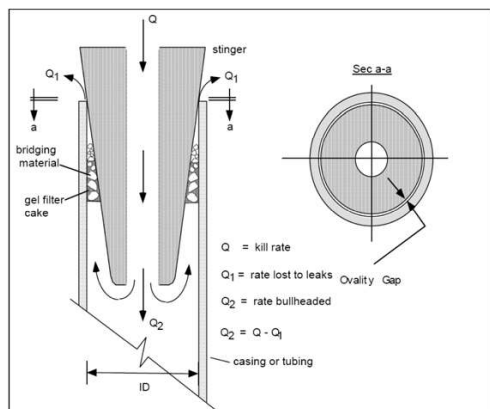


Figure F.14 Stinger Diagram

Example Given:

A flow from 7" (6.24 inch I.D.) to be stung

Determine:

The maximum wellhead pressure to limit pressure area effect to 30,000 lbs force.

$$30000 = \frac{(\pi)(6.25)^2}{4} \cdot \text{WHP}$$

$$\text{WHP} = \frac{30000}{30.67}$$

$$\text{WHP} = 977.8 \text{ psi}$$

Downhole conditions must be conducive for a bullhead kill for the stinging operation. Although a pump and bleed (volumetric kill) procedure will in theory be possible, the general idea is to sting in, pump the bridging agents to seal the leaks and then bullhead the well dead.

Once the well is killed, the objective will be to secure the well. The stinger and its bridging agent seal cannot in any way be considered a permanent barrier. There are several options available. Install a:

- Slip-on weld type head (if productive string is weldable material).
- Temporary wellhead or
- Capping assembly (swallow stub) and/or permanent wellhead and re-tension casing strings.

10.6.10 Conclusions

In recent years there have been great advances in the techniques for capping and controlling blowouts. Equipment and techniques continue to improve due to cooperative efforts by both the capping vendors and the oil operators. This chapter has spoken to a few of the principles of the capping operation. There are many topics concerning capping that were not discussed here. We caution the reader that capping is an "experience-intensive" activity and absolutely nothing can replace the sound judgment that has been gained from years of doing the job. Although procedures have been offered, they are in no way complete. They have not been given for the purpose of guiding the inexperienced to become a capping crew, but for general information to aid all concerned with these types of operations.

Capping operations depend greatly on the situation. However, the three major types of capping operations – capping to a flange, capping by installing a wellhead and capping to a casing stub - cover a vast majority of all well control jobs. Although typically regarded as a somewhat "unscientific" undertaking, certain calculations can and should be made to insure that the end result will allow the subsequent operations to proceed safely.

Advances in explosive and abrasive cutting technology have resulted in improved methods for removing damaged equipment and preparing wellheads for capping operations. This technology should be used to its fullest extent to maximize the safety and efficiency of the capping job.

Stinging operations are applicable where certain conditions prevail. Where the circumstances will allow the use of the stinger technique, it should be considered, since it is a safe and effective means to control a blowing well.

10.7 RELIEF WELL INTERVENTIONS

Implementation of a relief well as a well control technique basically involves establishing direct communication with the problem well by directional drilling of a hole to a specific down hole location in very close proximity to the problem well and at a depth sufficient that will allow overcoming the blowout flow. The interception of the wellbore should be adequate enough to communicate with the blowout flow of the problem well. This would be considered a direct interception allowing a more effective control of the blowout flow. Alternatively, the relief well can be designed to communicate to the blowing reservoir with intentions to alter the reservoir properties with a matrix flood using water or polymers. Regardless of the objective, the relief well must make a close pass or interception of the blowing well to be successful. If possible and as a precaution, the interception should be planned and positioned to intercept within the plane of the maximum principal stresses of the formation rock. This will improve the chances to effectively communicate with the blowing well via the matrix or an induced hydraulic fracture when a direct interception fails. When a proper communication is established, it should be possible to pump kill fluid at designed rates to kill the well.

10.7.1 Kill Well Techniques review

In attempting to classify kill techniques, it is convenient to consider those which can be implemented directly over the blowing well (direct kills), and those that require the drilling of one or several relief wells.

Blowout control methods include some 'pumping', whether directly through the top of the blowing well or at depth via a relief well. The four basic pumping techniques that blowout 'specialists' usually refer to are:

- Overbalance kill
- Dynamic kill
- Momentum kill
- Matrix kill or flood kill

The best practice, once it is obvious that a 'simple kill' of the hydrostatic nature for instance will be ineffectual, is to prepare and spud a relief well concurrently with eventual surface kill preparations. If the surface kill fails, much time will have been gained.

The situation of the blowout will dictate the objectives of the relief well. The reservoir data and geological model will determine the type of kill required and the number of relief wells to consider. Once this has been established, quantity estimates and the availability of the following can be made.

- personnel,
- equipment,
- supplies,
- services, and

When making these estimates, the tendency is to look only to the worst possible case. While this is advisable in a contingency plan, a moderate or most likely scenario should also be investigated. Having alternative plans other than the worst case event will help eliminate "overkill" and waste and allow the operator to move quickly in response to the emergency.

The further the surface location of the relief well is from drilled well, and the greater the depth to the intercept target, the greater the degree of precision required in directional control. The depth of the blowout has a major effect on how the well is killed. If relatively shallow (less than 3000 ft) it

will require a shallow kick-off depth which can complicate directional control. The softer clays encountered while trying to obtain the high build and drop rates and high drift angles necessary just add to the directional control problems. Later under reaming or hole opening operations are also more difficult in such soft and often unconsolidated formations.

As the point of intersection becomes deeper, drilling times increase. However, the longer drilling time will allow orderly planning and mobilization of special equipment, supplies, and kill personnel. On the other hand, the deeper horizons are typically at a higher pressure and, up to a point, more prolific. The special equipment must therefore be sized upwards to meet the higher pressure and volume requirements. The deeper horizons and added drilling depths impact negatively on navigation as the ellipse of uncertainty increases. It might require many passes and re-drills before the blowing well is cleanly intercepted.

The planned trajectory is merely a general guideline and not an absolute rule. The relief well is drilled in three major phases.

- Phase I: Drill directionally to a point in space that converges near the blowing well's casing or BHA, within range of wireline proximity logs.
- Phase II: Locate the relative position of the relief well to the blowing well using proximity logging techniques and sound judgment.
- Phase III: Converge with the blowout well at the desired interception point (or a very close pass by) to establish the necessary communication to kill the flow.

In reality, the plan for the well can only take the relief well to the start of Phase II. After the well is located using proximity techniques, the final trajectory design will take place.

10.7.2 Positioning the Relief Well

Positioning the relief well involves a number of objective and subjective considerations. Listed below are the general factors taken into account while positioning relief wells for a typical exploration well:

- Direction of the prevailing winds as defined by the regional wind roses.
- Direction and dispersion of oil by the offshore currents.
- Safety perimeter around the well surface location (350m ± 10m) based on minimum pollution levels at the surface location and heat radiation of a 120 mm³/d gas fire.
- The blowout's targeted bottom hole location and position uncertainty.
- The subsurface location of other wellbores.
- The presence of sea bed obstacles or installations such as pipelines
- Minimizing the distance and time to drill the relief well.
- Natural offshore characteristics which influence directional control
- The desired approach angle and direction in converging to the target.
- Degree of confidence in achieving a trajectory to interception.
- The depth at which interception must occur.
- Range and ability of proximity tools to detect casing or BHA (60 meters for induction tools / 50 meters passive magnetic).
- Maintaining as simple as possible trajectory and minimum dogleg severity; upper acceptable dogleg for planning purposes has been 2.0 deg/100 ft [667 deg/10 meters].



The position of the relief well is always more critical in an offshore location. Consideration needs to be given to current and wave behavior in the vicinity of the PTTEP location. The prevalent wind direction also dictates the location of the relief well.

Some of the factors in positioning the well include local regulatory and environmental considerations, the influence of the underwriters, the state of the seas and winds (current speed, direction, velocity, frequency), water depth, mudline conditions (debris, pipelines, sediments, obstacles, other wells), and the situation at the blowout site (size of the plume, type of well effluent, fires, surface cratering, state of the BOPE). There does not appear to be any minimum distance, except as dictated by specific conditions. Other factors relate to the well to be drilled, such as where the original well will be intercepted and the intercept trajectory. A site selected without due consideration of all relevant factors can result in increased difficulty and cost in reaching the desired objective. The location of the relief well for each blowout should be chosen based on its own merits.

More importantly, the relief drilling site and the relief well trajectory must not be compromised by any existing platform, wells, or well paths. It is difficult to conceive of a more extreme situation than a blowout at or near a producing platform, where numerous wells converge to the platform. The nearby wells interfere with ranging techniques and enhance the ellipse of uncertainty. These conditions might suggest that the blowing well be intersected as deep and as far away from the congested area as possible, even though the ellipse of uncertainty is greater. The platform scenario becomes more complex when multiple wells are blowing out, requiring multiple simultaneous relief well drilling operations. Every effort must be given to avoid any mooring pattern from overlapping other mooring patterns.

The general factors listed establish the preferred relief well location for a typical exploration well. An S-shaped trajectory for the relief well will usually suffice. This is the absolute shortest drilling distance that meets the objectives of the relief well and the 350 meter exclusion zone criteria. It represents an aggressive drilling trajectory with directional control, but compared to a simple J-shape that will require multiple plug backs, it is considered to be the most direct and efficient of all the possibilities. For a typical exploration well, a single relief location that is a sufficient distance from the well, but close enough that an aggressive drilling program is possible, is usually recommended. However, each case is unique.

10.7.3 Relief Well Target

In considering the relief well target, there are two distinct possibilities in the blowing well. The first is that the drillstring is on bottom and the other that the drill string is out of the hole, or pulled up inside the casing shoe (as in the string hung off before shearing the drillpipe). It is essential that there be metal (casing or drill string) in the blowing well for all types of proximity logs to function. If the target interception point is an open hole interval, the drill string must be across the target zone. If this is not the case, the target will be the deepest casing shoe. If the drill string is on bottom, the target can be where the blowing well penetrates the flowing reservoir. However, for planning purposes, the last casing shoe set is a target that is known to exist and therefore the most advantageous target as the primary initial target in Phase II. Should a blowout occur, the directional plan can be altered for deeper horizon targets when conditions justify such a change.

The Phase II objective will be converge to the blowing well at the estimated location of the deepest casing shoe. The relief well must be between 50 to 60 meters of horizontal distance from the blowout wellbore, and be approximately lined up (within 7 to 10 degrees in combined inclination and azimuth) when the end of phase II is reached.

Phase II begins when calculations show that the relief well has come within 50 to 60 meters of horizontal distance to the blowing well. (Note that the proximity logs measure distance between the two wells in a plane perpendicular to the well to be ranged to, therefore high angle wells may need adjustment of these criteria. At the depth of interest, the trajectory of the target wells in this



plan is vertical (or near vertical). Thus, the horizontal distance of 50-60 meters is valid without adjustment for inclination.

The first proximity survey can be made at the 50 to 60 meter range. However, one should not expect to receive definitive information until the distance between wells is 15 to 30 meters, and the most reliable information becomes available in the 1 to 15 meter range. Course corrections should not be made unless data from the proximity logs is in the 10 to 20 meter range, and confidence in the data collected is high.

Phase III, drilling to interception, is the most critical stage of the relief well project. Once the blowing well trajectory is determined, a precise trajectory can be determined for an interception. Given that confidence in the ranging data is attained, Phase III can begin.

The intercept point where the relief well and the flowing well are designed to come together is most usually at the bottom of the flowing well. This is normally where the flowing zone is found, except when serious pressure reversals exist. It is also the place where the kill fluid, when placed in the flowing well, has the greatest influence due to its having access to the entire drilled wellbore. An off bottom kill would require a higher kill mud weight to achieve a similar hydrostatic kill pressure. The bottom kill uses the lowest possible kill mud weight. However, bottom kill is not always the best approach. Lessons learned from the past tell us that in high permeability reservoirs (8 darcies, Ixtoc 1, June 1979) a bottom kill will never work.

The ellipse of uncertainty increases with depth so that more passes might be required before the flowing well can be hit with certainty. The deeper the well, the longer the drilling time. Temperature also increases with depth, so mud treatment becomes more complex. Ranging surveys and logging services also require more sophisticated methods at elevated temperatures. These effects, individually and collectively, increase operational costs. However, if the blowout well has several zones flowing, it might be necessary to consider a bottom kill *and* an off bottom kill.

Once the well is intercepted, the task will be to communicate directly with the blowing well. This communication will most likely occur by a breakthrough from the relief well to the blowout well when the wellbores are within 0.2 to 1 meter apart. This will depend on the flowing bottom hole pressure of the blowing well and the formation rock mechanics. In this case, the communication link should establish itself very quickly. It should become physically quite large (5 to 20 mm) and offer little if any flow restriction.

Once communication has been established, the objective shifts to pumping a sufficient volume of kill fluid into the blowing well, at an adequate rate to overcome and kill the hydrocarbon flow from the producing interval. Once control is achieved during the initial kill operation, both wells need to remain stable until abandonment or workover operations can take place. In no case should the kill operation expose the well to additional risk of unmanageable problems brought on by a worsening control situation. Reasonable judgment and practices should be taken in pursuing the kill operation. The kill should not be irreversible, nor should it unduly eliminate reasonable kill alternatives if the initial attempts fail. An example of an irreversible operation would be attempting to kill the well with cement rather than drilling mud. The overall plan should take this philosophy into account.

There is a remote possibility that in spite of best efforts, the relief well will miss the blowing well and make a close pass, perhaps 1 to 2 meters away. If a direct communication is not possible, it may be necessary to plugback to intercept. Depending upon the distance between wellbores, an acid job in carbonate rock may be considered to establish communication. This will work best if the relief well bore is in the pressure draw-down of the deepest producing zone. If this is the case, the acid will travel naturally through the matrix of the producing zone and into the blowing wellbore. A worm hole path will be created and the net result will be the creation of a direct communication between the two wellbores. This option should be carefully studied before implementation as there are many acid treatment designs using gels, retarders and concentrations to consider. Direct communication established through interception is better than relying on an acid job to create a

worm hole. Fracturing the rock matrix should be avoided, but if fracturing is to be attempted, then rock stresses will dictate the direction of the fracture path. If the intercept is not in the plane of the maximum rock stresses then the fracture will never intercept the blowing wellbore. Other options are perforating or milling techniques, if communication is to a cased hole.

10.7.4 Casing Design and Seat Selection

The relief well casing design and seat selection must meet both the requirements of the kill operation and the normal regional drilling conditions. The ultimate objective of the relief well is to overcome and kill the flowing well. The conditions imposed by this objective are additional requirements beyond the normal casing design.

Casing strings should be designed against the following conditions:

Regulatory agencies may set the minimum-design conditions they expect to see in wells drilled in their jurisdiction, relating to whether or not the well must contain the full pressure at the surface, the safety factor for collapse, and so forth. Typically, they will dictate the maximum setting depth for the surface string to protect any ground water supplies.

These conditions could be pressures during kick operations such as shutting in the well, circulating out the kick, or the pressures that could build if the pipe is sheared.

However, additional factors might need to be taken into account as the direct result of the blowout. If too little casing is set, there is the real problem of loss of circulation or worse, or even stuck pipe if differential pressures become extreme. If too much casing is set, you can run out of hole as the resultant hole size becomes too small to handle the large kill flow rates required.

- What is the impact on well design by the reservoir?
- Will the casing be of sufficient capacity to allow the high volume pumping required for the kill operation?
- Will the casing design allow for a back-up string in the event an additional string is required?
- Are any shallow zones pressure charged? Is the reservoir expected to be depleted in the vicinity of the wellbore?

These unique conditions that occur in the relief well are not common to ordinary wells. In an underground blowout, for example, there can be charging of upper formations or depletion of deeper formations. This may significantly alter previously observed conditions and present new problems during the drilling process. Additional factors have been considered and evaluated in addressing the relief well design:

- Effects of well casing configuration on the friction and flow rates required during the kill operation.
- Implications of setting an additional casing string to combat downhole problems encountered during drilling, i.e. can the objective still be attained if a further reduction in hole size is required or additional strings set.
- Realistic possibility of individual zones being artificially pressured or depleted and there is information to support this position.

Besides the above, certain questions should be reviewed before spudding the relief well, to take advantage of the most current information:

- Has the target location changed significantly since the relief well plan was developed?

- Were there complications encountered in the original blowing well during the up hole sections which could threaten the success of the relief well? How will these be averted?
- Will the casing schedule have to be modified to meet the directional drilling objectives required to intercept the blowing well?
- Was there an unanticipated presence of a corrosive or toxic fluid such as CO₂ or H₂S requiring special consideration?

If the relief well is to be considered as a replacement well for the blowing well then future requirements for production and stimulation must also be taken into consideration in the overall design. These details have not been covered by this study because it is thought that stimulation or productive casing loads are not to be applied to a relief well casing string. In other words, the relief well is thought of as a sole purpose well and not a producing well. The casings as detailed for a typical developmental and exploration well have been reviewed, and are adequate for all relief well loadings and conditions. Open hole and casing loads imposed by the kill operation have also been considered.

10.7.5 Ellipsoid of Uncertainty

The primary objective is to intersect the blowing well at some predetermined subsurface point (in this case the top of the producing formation). It must be realized that various factors detract from the ability to reach that point with pin point accuracy. The influence of the various factors is frequently described as the "cone of uncertainty." Normal directional well targets are usually a two dimensional circle or rectangle in the horizontal projection. The relief well must view the producing well's trajectory in a three dimensional perspective. Consideration is given to possible inaccuracies in, or lack of, survey data. As a result, rather than having a specific point for the target for the relief well, it becomes in reality an ellipse which is commonly referred to as the "ellipsoid of uncertainty".

While some would argue that an ellipsoid applies only to outdated directional survey tools, such as the single shot or multi-shot (not the EMS), it is still considered a standard to think of wellbore uncertainty as an ellipsoidal shape. High accuracy tools, such as the North seeking gyro, have equal accuracy in azimuth as they do in inclination, and therefore the ellipsoid would truly be a sphere.

The factors which influence the relationship of uncertainty in a relief well situation can be summarized as:

- Accuracy of the survey on the surface location (2 meters).
- Type of directional survey equipment employed and their inherent inaccuracies.
- Ability to confirm the well trajectory using different methods of measurement.

The following criteria are a guideline for the preparation of this relief well contingency plan:

- Initial spotting of the rig on the relief well location must be accurate to within 5 meters of the desired position. Surveys must be recalculated through interactive measurements until the accuracy is within 2 meters by the time the kickoff point is reached.
- Three types of survey tools will be used, the MWD, EMS and a North Seeking Gyro. Although not a directional tool the proximity tools will influence the degree of uncertainty. The tools will be supplied by the local directional or surveying vendors.

- The use of the three types of survey equipment in both open and cased hole will serve to verify the accuracy and repeatability of the surveys. Proximity tools will determine the relative position of the wells to each other once the wellbores converge within the tool's range. Details on the survey program will be provided under the topic "Directional Control."

The reliability of a relief well plan depends not only on the ability to accurately measure the hole position, but also on the prescribed directional program. On paper, a wide variety of relief well trajectories are possible, but in practice only a few are practical. The selection of a relief well location and the planned trajectory go hand-in-hand. As discussed earlier, a great number of considerations are involved in the selection of the relief well location. The weighting of the various considerations relative to this plan has been biased by:

- Desire to minimize the necessary drilling time by picking a kickoff point as deep as possible and planning a trajectory which minimizes survey requirements, eliminates additional motor runs and doesn't automatically require plugback operations.
- Avoidance of difficult directional maneuvers or approaches to minimize the possibility for failure.
- Availability of reasonably accurate survey data on the blowout wells makes it sensible to plan a relief well trajectory with a fairly deep initial crossing point for wellbore location.

10.7.6 Directional Control and Surveying Requirements

Maintaining a high degree of accuracy in the relief well directional control is essential for success. A successful relief well can be assured if stringent directional control is maintained.

- The relief well intersect of a blowing well is contingent on the ability to accurately map the blowing well's path from the surface to the bottom of the hole.
- A consistent directional survey program is the key to this goal.
- Inconsistencies in the directional data should be backed up by additional surveys resolve the differences.

10.7.7 Surveying Requirements for the Relief Well

The relief well directional program will follow a trajectory from the selected surface location to a point in close proximity to the wellbore of the blowing well. At that point proximity tools will detect the casing in the target wellbore. Once the target wellbore is located, the existing blowout directional surveys are tied into the proximity tool's results to guide the relief well to interception.

Survey data obtained in the relief well should maintain a high degree of accuracy in order to reach the interception objective. The survey policy for a typical exploration well is adequate for the depth of the wells, considering the range of the proximity logs. Full-time use of MWDs should now commence. Run a North seeking gyro to confirm the location below the kickoff point in the relief well before running surface and protective casings. Use the same vendor's downhole survey tools as were used in the blowout well, in order to limit tool characteristic variables. Duplication of data accuracy between wells is best achieved if any variance in tool characteristics is minimized.

Avoid collision except at the point of interest. When the relief well comes into the vicinity of any wellbore, it may be necessary to run proximity tools to verify that a premature collision will not occur. Note that Phase II of the drilling of the relief well begins when the calculated distance between the wells is about 60 meters. Proximity logs are used to avoid an early collision. If a collision is eminent, course corrections may be required to guide the relief well safely past the wellbore to the intended target.

10.7.8 Converging to a Blowing Well

Provided the directional surveys for the blowing well are reasonably accurate, it should be possible for the relief well to drill directly to the vicinity of the deepest casing shoe or the BHA left in the blowing well. The convergence path of the relief well presented in this plan should have a combined difference in both azimuth and inclination of less than 10 degrees from that of the target well. If the target well is to achieve this path, the relative position of the relief well to target well must be established at considerable distance from the crossing point. The radius of uncertainty can create a situation where it is very unlikely that an interception could be achieved using directional techniques alone (e.g. drill to a point in space without ranging to the target).

In essence, the proximity tool reduces the ellipse of uncertainty. For relief well plans, there are two primary types of proximity tools. One derives its ability to detect an adjacent well through an induced electrical field, while the other measures the magnetic flux between the tool and the casing or bottomhole assembly in the target well. Regardless of the tool used, metal (iron for the passive tool) in the BHA or casing of the relief well is required for these tools to work. If there is cased wellbore nearby, the interpretation can be difficult. Both proximity tools have unique sets of strengths and weaknesses so use both to take advantage of each tool's strengths.

10.7.9 Induction Tool

The induction tool makes use of an induced electromagnetic process which effectively, allows detection of a well within 50 to 90 feet. The inductive electromagnetic process requires the tool to be run in open hole. If the emitting electrode cannot be placed in open hole, the range is reduced to about 30 to 40%. For best results with the electric process range, the induction tool should be run in at least 100 meters of open hole. Open hole logging can be a major drawback if hole conditions are not optimal. A method used to overcome this problem has been to run open-ended drill pipe to just above the depth near the point of investigation. The tool is then run inside the drillpipe and allowed to exit into the open hole.

10.7.10 Passive Magnetic Surveys

The passive magnetic tool has detected casing at 150 feet. This process isn't strongly influenced by being run inside a non-magnetic drill collar, and is the preferred method of making the survey. The ability to run inside the string saves valuable rig time by eliminating trips. Although used to detect pipe at a distance of 150 feet, the accuracy of the passive tool is generally better within a 40 to 60 foot range of the target wellbore.

10.7.11 Intercepting and Establishing Communication

Under the conditions presented by a typical exploration well, direct interception of the blowing well in the open hole, at or below the top of the producing interval, should be the primary objective. If the well is cased, the objective will be to pass near the top perforation. The ideal point for the relief well to intercept the target well is at the top of the main reservoir, where kill weight fluid will be injected directly into the flow at its source. It is possible that a direct intercept cannot be accomplished, but adequate communication can be established between the wells. Since the reservoir is limestone, the communication can be through the rock matrix. Acid may be used to remove mud damage and open up the permeability if required.

If the target well is not intercepted, and acid fails to open up a sufficient flow path, more drastic methods may be required to establish communication with the well. The options will vary depending on the individual situation, but may include such operations as fracturing between wells or perforating the formation with a tubing conveyed shaped charge, oriented toward the target wellbore. However this option is considered a remote possibility because the confidence for making a wellbore interception is very high.



Despite the means necessary to establish communication, all preparations to perform the kill operation must be in place before drilling the final segment of the relief well. If an intercept is attained, there will be no option but to immediately commence the kill operation.



10.8 RELIEF WELL PLANNING

The purpose of this Appendix is to provide a generalized guideline for drilling a relief well. Information that is common to relief well planning and implementation is contained in this section. This Appendix does not address fully site specific issues for any particular reservoir or field.

It is important to remember that every blowout has a unique set of circumstances from which the majority of the planning process is directed. However, the strategy applied here is acceptable since the primary purpose of this appendix is to familiarize local personnel with some of the special techniques and services associated with planning a HTHP relief well. If an actual emergency were to occur, this planning process would have already been established and would save valuable time in a real intervention situation.

10.8.1 General Commentary on Relief Wells

The primary purpose of drilling a relief well is to kill an uncontrolled flow from a blowing well that cannot be reliably controlled at the wellhead by capping operations. One such example is when the well has cratered and there is no access to the wellhead leaving the relief well as the only feasible alternative. Another case is deep water wells where an offset re-entry kill is not possible. However, if the wellhead is accessible, capping operations are successful in controlling the well more than 97% of the time (making relief wells low probability options). While relief wells have been responsible for controlling only a minor number of all blowouts, they are an important part of well control capabilities.

The relief well is a special type of directional well. It is drilled from a surface location in as close a proximity to the surface well as possible. Its purpose is to provide a conduit, down which a kill mud of adequate weight can be pumped in sufficient quantities to arrest the blowout. The kill procedures might include the momentum kill, the dynamic kill, or flooding the reservoir. In practice, the trajectory of the kill well is designed to intersect the blowing well just above and as close to the inflow zone as possible. Casing or drillpipe is then set as close to this point as possible, prior to any attempt to kill.

Uncontrolled flows fall into two general categories: underground and surface blowouts. Subsea blowouts where the exit point is to the seabed are also classified as surface blowouts. Regardless of the exit point of the flow, the relief well will have the objective of a very close pass by, or an intercept of, the wellbore of the blowing well if it is to be successful (see Figure A.1). This will be at depth sufficient to kill the flow by pumping a kill fluid from the relief well into the blowing well. The interception of the wellbore should also communicate to the blowing well and create a viable flow path for the kill fluid from the relief wellbore. Alternatively, the relief well can communicate to the blowing reservoir to perform a matrix flood of the reservoir to control the well.

The situation of the well dictates the objectives of the relief well. In the preplanning phase, it is necessary to make educated guesses based on several likely scenarios. Much information is needed to describe the reservoir, such as its pressure, permeability, porosity, reservoir limits, and most importantly, the reservoir deliverability. This information is then used to determine the type of kill most likely to achieve the desired objective, the number of relief wells likely to be required, an estimate of the personnel, equipment, supplies, and services needed, and a timetable for the event.

When making these estimates, the tendency is to look only to the worst possible case. While this is advisable in a contingency plan, a moderate or most likely scenario should also be investigated. Having alternative plans other than the worst case event will help eliminate "overkill" and allow the oil operator to move quickly in response to the emergency.

Several case histories offer valuable insights into contingency planning for relief wells. Beginning with a Texas panhandle event in 1982, there have been three major events where the operator planned complicated kill operations from relief wells. These blowouts were all 'engineered' as

large volume, massive horsepower kill operations. At the end of the day, the exotic and costly kill operations were not required and therefore only served to fulfil the perceived design requirement.

In a 1989 North Sea control operation, preparations were made for a high horsepower, large volume pump job designed for what was perceived to be a worst case scenario. About 9,600 HHP was rigged up and kept on a constant state of readiness for 6 months. Upon interception of the blowing borehole with the relief well, the fluid in the relief well U-tubed by gravity into the blowout well, killing it in a few minutes, and none of the high pressure horsepower pumping spread was employed to kill the well. Pumping requirements were limited to keeping the relief well hole full, which was accomplished with a single cement pump unit carried on board as part of the basic rig components. These wells are examples of "overkill" in the pumping requirements and the failure of the designers to account for the drawdown of the blowing well. On the contrary, if the reservoir is very strong (little depletion) large pump pressure and horsepower kill operations will be required. Another source of overkill in a relief well plan is excessive use of safety factors. If the reservoir parameters, leakoff losses, kill requirements, frictional pressures and pumping output all have safety factors applied individually, the overall result will be massive pumping spreads and volumes.

In the USA, there were two deep, high pressure wells which blew out in 1982 and 1985. Both wells were controlled by relief wells. The plans again called for high pressure/volume pumping kill operations. In both cases the kill volumes and pressures necessary were much less than anticipated. In these cases, as in the previously described North Sea operation, fluid in the relief well U-tubed into the blowing well on interception without assist from applied HHP from the surface. This again made the kill operation merely "keeping the relief well hole full". Minimal assistance from the surface pumping equipment rigged up specifically for the kill operation was required, and in the opinion of the author, not justified. All wells were controlled by keeping the relief well full, at average pumping rates of less than 10 bbls per minute, until about one hole volume U-tubed into the blowing well. Thereafter, the wells were under control and circulation established.

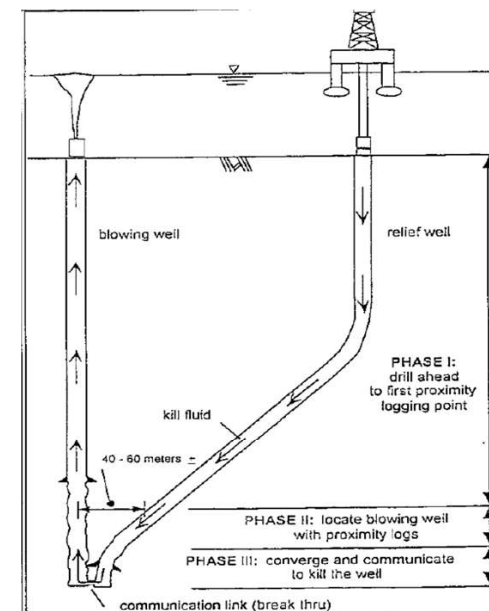
The point to be taken from these case histories is that there may well be a scenario where the blowout can be killed with conventional equipment, resources found in normal drilling operations, and may not require massive pumping spreads. However, there are situations in which a significant amount of hydraulic horsepower and kill volume is required. A concerted effort to offer both the worst case possible and a reasonable kill plan for a dynamic kill from a relief well is necessary.

10.8.2 General Trajectory and Objectives of the Relief Well

In simple terms, the relief well is a directional well that unlike the common directional well has a small, well defined target. Otherwise, the attributes are the same as a common directional well. The main objective will be to establish a direct communication with the blowing wellbore. This communication is the single most critical element in the success of the relief well. The accuracy of present technology for locating blowing wells with wireline proximity logs enables an interception or 'hit' of the blowing well to establish a direct communication link. The confidence for an interception is very high. In the last ten years, every relief well that has been drilled to objective with an interception in mind has been successful in achieving that goal.

To a large extent, the greater the depth of water the more the water will act as a buffer or choke to restrict the effluent flow. Gas will not escape as readily. Gases such as methane and hydrogen sulfide partially dissolve in the water, so their effects are lessened. Gases normally will not adversely affect operations where water depths exceed 1200 feet. The deeper the water, the less the reservoir drawdown, so kill pressures are higher. In some cases, reservoir conditions might cause localized depletion around the wellbore so kill pressures are lower. The further the surface location of the relief well is from drilled well, and the greater the depth to the intercept target, the greater the degree of precision required in directional control. For deeper water operations, the

offset well might be drilled in close proximity to the original well and track that well until close to the planned point of interception.



Relief Well Drilling Phases

The depth of the blowout has a major effect on how the well is killed. If relatively shallow (less than 3000 ft) it will require a shallow kick-off depth which can complicate directional control. The softer gumbo-type clays encountered while trying to obtain the high build and drop rates and high drift angles necessary just add to the directional control problems. Later under-reaming or hole-opening operations are also more difficult in such soft and often unconsolidated formations.

As the point of intersection becomes deeper, drilling times increase. On the one hand, the longer drilling time allows more orderly planning and mobilization of special equipment, supplies, and kills personnel. On the other hand, the deeper horizons are typically at a higher pressure and, up to a point, more prolific. The special equipment must therefore be sized upwards to meet the higher pressure and volume requirements. The deeper horizons and added drilling depths impact negatively on navigation as the ellipse of uncertainty increases. It might require several passes and re-drills before the blowing well is cleanly intercepted.

Besides establishing a communication link to the blowout well, the relief well hole must be maintained in such a state that the drillstring can be easily tripped in and out. The hole must be maintained for logging casing running and cementing operations, and most importantly, for well killing operations. Whenever possible, hole problems such as loss of circulation and sticking must be solved so that continuing progress can be made. If downhole drilling problems are not resolved, the well may not reach its objective. Progress cannot sacrifice these essential parameters. For example, the hole will be useless if proximity logs cannot be run without causing a fishing job.

The major differences between relief well and ordinary directional wells are that the target is much smaller and fluid injection rather than production will be the prime concern. In some cases, the target may be only inches wide, as in the Texas Panhandle well, Apache Key #1-11, where the objective was to hit a 5" liner at 16,080 feet (4902 m) TVD. In other cases, the target can be quite large as in matrix kill operations (Aramco Berri #34, 1979, where horizontal separation was approximately 40 feet). In this case the formation characteristics allowed the relief well to converge to a near passby of the target wellbore rather than an interception. Regardless of the type of kill operation desired, the ability to drill to a well-defined target will enhance the chance of success for the kill operation. Bearing in mind the small size of the target and the limited range (50-60 meters maximum) of the proximity tools, a relief well must be drilled with consideration for necessary course corrections.

The planned trajectory is merely a general guideline and not an absolute rule. The relief well is drilled in three major phases as illustrated in Figure H.1:

- Well's casing or BHA, within range of wireline proximity logs.
- Phase II: Locate the relative position of the relief well to the blowing well using proximity logging technique and sound judgment
- Phase III: Converge with the blowout well at the desired interception point (or a very close passby)

In reality, the plan for the well can only take the relief well to the start of Phase II. After the well is located using proximity techniques, the final trajectory design will take place.

10.8.3 Positioning the Relief Well

Positioning the relief well involves a number of objective and subjective considerations. Safety considerations are more straightforward and require prudent decisions. The trajectory required for interception strongly influences well placement, and involves more complex decisions based on the anticipated ability to achieve the prescribed directional drilling program. Listed below are the general factors taken into account while positioning relief wells:

- Direction of the prevailing winds as defined by the regional wind roses.
- Direction and dispersion of oil by the currents.
- Safety perimeter around the well surface location (as required) based on minimum pollution levels at the surface location and heat radiation.
- The blowout's targeted bottom hole location and position uncertainty.
- The proximity of other surface facilities or wells.
- The subsurface location of other wellbores.
- The presence of sea bed obstacles or installations such as pipelines.
- Minimizing the distance and time to drill the relief well/
- Natural regional characteristics which influence directional control.
- The desired approach angle and direction in converging to the target.
- Degree of confidence in achieving a trajectory to interception.
- The depth at which interception must occur.
- Range and ability of proximity tools to detect casing or BHA (60 meters for induction tools/ 50 meters passive magnetic).

- Maintaining as simple as possible trajectory and minimum dogleg severity; upper acceptable dogleg for planning purposes has been 2.0 deg/100 ft. [0.667 deg/10 meters].

The position of the relief well is most critical in an offshore location. Figure H.2 is excerpted from a Blowout Contingency Plan where factors listed above have been considered.

Most likely, the casing will be detected before a crossing occurs, and a mid-course correction made for an interception at the producing interval. However, if casing is not detected by the time that the deepest casing target point is reached, the relief well will drill ahead, holding angle and direction, until casing is located or total depth of approximately 20 meters above the reservoir is reached. If casing is still not located, the well must be plugged back and turned to a new target. Care must be taken to not penetrate the reservoir before protective casing is set. Once casing has been detected with proximity logs, the relief well will be turned and guided to make an interception at or near the reservoir penetration. The deepest casing point was chosen as the Phase II target because, unlike the drill string, it will always be in place. It is at sufficient distance up hole from the interception target that course corrections are possible to carry through an interception of the blowing wellbore.

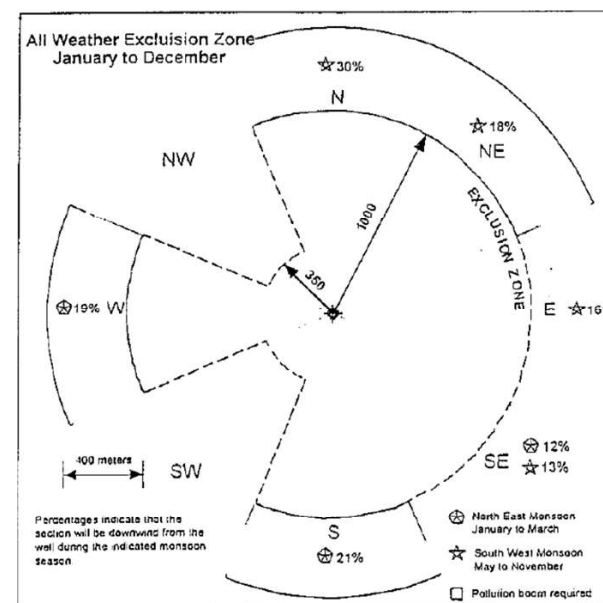


Figure H.2 Exclusion Zone Example for An Offshore Relief Well.

Phase I should be drilled in a manner similar to that of any other development well. The drill site for the relief well must be chosen with care. Particular attention must be paid to the surface location of the well, and to accurate directional control. The surface location must be accurate to within 5 meters when moving the rig onto the desired location. Thereafter, the surface location of both the blowout and the relief well should be resolved to within plus or minus 1 meter accuracy.

The relief well site will often be a compromise based on several conflicting or complimentary factors. Some factors will point to a specific direction and location while others will point to contrary directions or locations.

Some of the factors in positioning the well include local regulatory and environmental considerations, the influence of the underwriters, the state of the seas and winds (current speed, direction, velocity, frequency), water depth, mud-line conditions (debris, pipelines, sediments, obstacles, other wells), and the situation at the blowout site (size of the plume, type of well effluent, fires, surface cratering, state of the BOPE). There does not appear to be any minimum distance, except as dictated by specific conditions. For example, the intensity of the fire, if present, might require the relief well be situated a thousand feet or so away from the heat source. Other factors relate to the well to be drilled, such as where the original well will be intercepted and the intercept trajectory. A site selected without due consideration of all relevant factors can result in increased difficulty and cost in reaching the desired objective. A single site can rarely be optimally located to serve multiple blowouts. The location of the relief well for each blowout should be chosen based on its own merits.

More importantly, the relief drilling site and the relief well trajectory must not be compromised by any existing platform, wells, or well paths. It is difficult to conceive of a more extreme situation than a blowout at or near a producing platform, where numerous wells converge to the platform. The nearby wells interfere with ranging techniques and enhance the ellipse of uncertainty. These conditions might suggest that the blowing well be intersected as deep and as far away from the congested area as possible, even though the ellipse of uncertainty is greater. The platform scenario becomes more complex when multiple wells are blowing out, requiring multiple simultaneous relief well drilling operations. Every effort must be given to avoid any mooring pattern from overlapping other mooring patterns.

The general factors listed establish the preferred relief well location for a typical exploration well. An S-shaped trajectory for the relief well will usually suffice. This is the absolute shortest drilling distance that meets the objectives of the relief well and the 350 meter exclusion zone criteria. It represents an aggressive drilling trajectory with directional control, but compared to a simple J-shape that will require multiple plug backs, it is considered to be the most direct and efficient of all the possibilities. For a typical exploration well, a single relief location that is a sufficient distance from the well not to create a hazard for the drilling crew, but close enough that an aggressive drilling program is possible, is usually recommended. However, each case is unique.

10.8.4 Discussion of Relief Well Targets

In considering the relief well target, there are two distinct possibilities in the blowing well. The first is that the drillstring is on bottom and the other that the drill string is out of the hole, or pulled up inside the casing shoe (as in the string hung off before shearing the drillpipe). It is essential that there be metal (casing or drill string) in the blowing well for all types of proximity logs to function. If the target interception point is an open hole interval, the drill string must be across the target zone. If this is not the case, the target will be the deepest casing shoe. If the drill string is on bottom, the target can be where the blowing well penetrates the flowing reservoir. However, for planning purposes, the last casing shoe set is a target that is known to exist and therefore the most advantageous target as the primary initial target in Phase II. Should a blowout occur, the directional plan can be altered for deeper horizon targets when conditions justify such a change.

The Phase II objective will be to converge to the blowing well at the estimated location of the deepest casing shoe. The relief well must be between 50 to 60 meters of horizontal distance from the blowout wellbore, and be approximately lined up (within 7 to 10 degrees in combined inclination and azimuth) when the end of phase II is reached.

Phase II begins when calculations show that the relief well has come within 50 to 60 meters of horizontal distance to the blowing well. (Note that the proximity logs measure distance between the two wells in a plane perpendicular to the well to be ranged to, therefore high angle wells may need

adjustment of these criteria. At the depth of interest, the trajectory of the target wells in this plan is vertical (or near vertical). Thus, the horizontal distance of 50-60 meters is valid without adjustment for inclination.

The first proximity survey can be made at the 50 to 60 meter range. However, one should not expect to receive definitive information until the distance between wells is 15 to 30 meters, and the most reliable information becomes available in the 1 to 15 meter range. Course corrections should not be made unless data from the proximity logs is in the 10 to 20 meter range, and confidence in the data collected is high. Figure H.3 shows how the first proximity log run can be calculated. This is of course based on the survey accuracy of the tools used.

Phase III, drilling to interception, is the most critical stage of the relief well project. Once the blowing well trajectory is determined, a precise trajectory can be determined for an interception. Given that confidence in the ranging data is attained, Phase III can begin.

The intercept point where the relief well and the flowing well are designed to come together is most usually at the bottom of the flowing well. This is normally where the flowing zone is found, except when serious pressure reversals exist. It is also the place where the kill fluid, when placed in the flowing well, has the greatest influence due to its having an access to the entire drilled wellbore. An off-bottom kill would require a higher kill mud weight to achieve a similar hydrostatic kill pressure. The bottom kill uses the lowest possible kill mud weight.

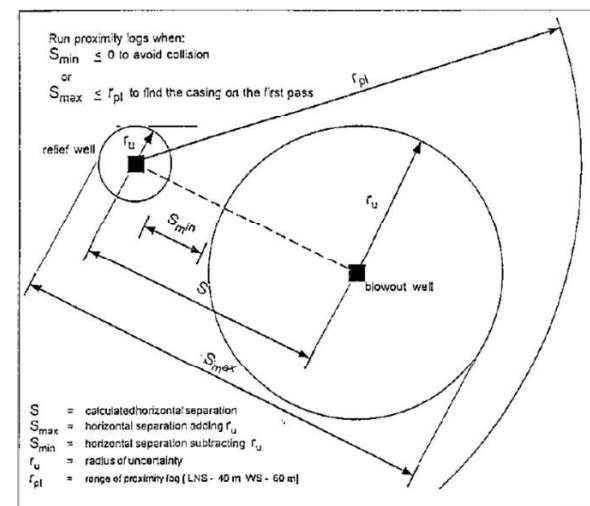


Figure H.3 Radius of Uncertainty Defined

The ellipse of uncertainty increases with depth so the more passes might be required before the flowing well can be hit with certainty, the deeper the well, the longer the drilling time. Temperature also increases with depth, so mud treatment becomes more complex. Ranging surveys and logging services also require more sophisticated methods at elevated temperatures. These effects, individually and collectively, increase operational costs. However, if the blowout well has several zones flowing, it might be necessary to consider a bottom kill and an off-bottom kill.

Once the well is intercepted, the task will be to communicate directly with the blowing well. This communication will most likely occur by a breakthrough from the relief well to the blowout well when the wellbores are within 0.2 to 1 meter apart. This will depend on the flowing bottom hole pressure of the blowing well and the formation rock mechanics. In this case, the communication link should establish itself very quickly. It should become physically quite large (5 to 20 mm) and offer little if any flow restriction.

Once communication has been established, the objective shifts to pumping a sufficient volume of kill fluid into the blowing well, at an adequate rate to overcome and kill the hydrocarbon flow from the producing interval. Once control is achieved during the initial kill operation, both wells need to remain stable until abandonment or workover operations can take place. In no case should the kill operation expose the well to additional risk of unmanageable problems brought on by a worsening control situation. Reasonable judgment and practices should be taken in pursuing the kill operation. The kill should not be irreversible, nor should it unduly eliminate reasonable kill alternatives if the initial attempts fail. An example of an irreversible operation would be attempting to kill the well with cement rather than drilling mud. The overall plan should take this philosophy into account.

There is a remote possibility that in spite of best efforts, the relief well will miss the blowing well and make a close pass, perhaps 1 to 2 meters away. If a direct communication is not possible, it may be necessary to plugback to intercept. Depending upon the distance between wellbores, an acid job may be considered to establish communication. This will work best if the relief well bore is in the pressure draw-down of the deepest producing zone. If this is the case, the acid will travel naturally through the matrix of the producing zone and into the blowing wellbore. A worm hole path will be created and the net result will be the creation of a direct communication between the two wellbores. This option should be carefully studied before implementation. Direct communication established through interception is better than relying on an acid job to create a worm hole. Fracturing the rock matrix should be avoided. Other options are perforating or milling techniques, if communication is to a cased hole.

In many old gas storage wells, the casing has become so corroded that conventional workover tools cannot enter the lower section of the hole. Techniques have been developed to mill a window from the outside of the casing from a relief well. The precision of this technique has allowed liners to be run into the lower section to tie it back to the original wellbore. If necessary, tubing-conveyed perforations can be used to make the communication. However, the authors are confident that milling can be used to cut a window in casing from the outside, if the blowout target is cased and a direct communication is needed.

10.8.5 HPHT or High Volume – Bottom Supported Operations

The following guide outlines the non-routine steps that would be considered in planning an actual high pressure high temperature (HPHT) relief well drilled in an offshore environment.

Define Objectives

The first step in this procedure is to establish the kill principle. Due to high pressures and temperatures, blowout flowrates, depths, reservoir characteristics, relief well casings and other factors the only practical method for controlling a HPHT blowout, that is not severely choked, is by direct intersection with the blowout wellbore followed by a dynamic injection of kill fluid.

Several hydraulic methods should be investigated, such as; dynamic kill with sea-water followed by mud, dynamic kill with brine followed by mud and mud as the only kill fluid. The method utilized would be dictated by the circumstances at the time of kill.

With this principle established, a primary objective will be to determine the relief well(s) placement, depth and proximity to the blowout to hydraulically regain its control. This information is required to arrive at a suitable well geometry.

Secondary objective is planning the hydraulic design. This information is necessary to design the casing program, to determine the number of required relief wells, and to specify the necessary surface and special equipment, rig requirements. Support vessels, etc.

Establish Kill Point

The kill point will usually be either at the last casing string set, along the drillstring or below the bit. The driving factors are; the bottom hole temperature at the reservoir, which will affect precision directional drilling and the kill rates required at the last casing shoe and the fracture gradients or potential weak zones affected by the kill.

Other elements to be considered are;

- Status of the blowout casing / wellhead
- Reservoir inflow performance and characteristics
- Blowout flow path and tubing performance
- Blowout fluid and kill fluid properties
- Formation drill ability
- Surface and special equipment required
- Risk analysis and probability of success.

Kill Program Design

Once the hydraulic kill principle, the kill depth, and proximity to the blowout wellbore is established, detailed planning can begin. The following steps are evaluated in this process;

Hydraulic Design

The hydraulic requirements for a kill on a HPHT well are complicated and require a two-phase time transient analysis to design the relief well casing, surface pumping plant, kill fluid volumes, final kill mud weight and pumping schedules to avoid fracturing the formation. Hydraulic planning process is an iterative process that may require several loops to arrive at an acceptable solution. The relief well kill simulations can be generated using "OLGA-Well-Kill", a dynamic-multiphase-hydraulic computer simulator, maintained by Well Flow Dynamics a/s.

Surface Kill Equipment

The kill hydraulics for a HPHT blowout, depending on the circumstances, can be immense. This will require a significant kill pumping plant, large mud storage and mud transfer capacities, and

monitoring capability. Other special equipment will be a high pressure two-four outlet kill spool with a 10,000+ rating and long steel flexhoses to connect to the subsea wellhead if a floater is being used to drill the well. If possible a large jack-up would make the best relief well and killing platform for a HPHT blowout, assuming shallow gas charging is not a problem.

Casing Design

While conventional casing design criteria are employed when designing a HPHT relief well, several additional considerations must be investigated. The first is to design the kill string diameter to assure that the control fluids can be pumped at the required rate without excessive surface pressure. The second is to allow for at least one additional, emergency casing string to assure the required kill string diameter can be set. A third is to establish strength requirements for the casing strings that might be exposed to higher than normal burst and collapse forces during kill pumping, well control or complete loss of circulation. A fourth is environmental considerations, such as hydrogen embrittlement on high strength casing and connections, casing wear, high dogleg considerations for bending stresses, thermal loading and temperature effects during kill operation (e.g. cold fluid being pumped down a hot well at high rates will cause high thermal tensile stresses).

Rig % Surface Equipment

After the kill hydraulics and relief well casing program has been established, rig and surface equipment requirement can be investigated. This is again an iterative step, requiring an analysis of equipment and available rig specifications, their ability to achieve the initial design goals and then repeating the process until a successful outcome is expected.

Surface Equipment

- High and low pressure pumps
- High and low pressure manifolds
- Mud tanks and mixing equipment
- Water, mud and diesel supplies
- Mud supply vessels and transfer equipment
- Stimulation vessels

Rig(s) Selection

- Rig specifications
- Deck layout for kill equipment
- Special kill equipment
- Kill spools
- Long co-flexip hoses
- High pressure riser, etc.

Relative position uncertainty

One of the first steps in relief well geometry planning is to estimate the relative position uncertainty for the blowout and the proposed relief well(s). This is essential for determining the initial magnetic search depth, the number of relief wells required, and the angle of approach. Both the uncertainty in the surface positions and the borehole trajectory must be analysed.

Surface Uncertainty

More than one relief well has missed its intended target do to errors in, or misunderstanding, the surface coordinates and azimuth reference system of the two wells. To avoid this costly mistake, redundant surveys should be taken between the blowout and the relief well wellheads using different measuring techniques.

The main objective is to assure that no gross errors exist in the primary positioning system. The secondary objective is to fix the relative distance and true north bearing between the two surface locations to an uncertainty of +/- 1m, with a high degree of confidence.

For relief well drilling purposes only the relative position of the two wells is important (as opposed to UTM coordinates or Latitude/Longitude). Additionally, it is important to assure that a common azimuth and depth reference system is being used. This has caused many directional drilling problems in the past, particularly when switching between grid systems and magnetic / true north reference systems. Normally three independent measurements are sufficient to assure reasonable confidence in relative positioning, one using geodetic surveying techniques and sun-shots for true north reference if possible, to eliminate any grid errors.

Borehole Uncertainty

This step is essential in determining the initial magnetic search depth, the number of relief wells to start, and the angle of approach. This can be a complicated and confusing task. Reliance on position uncertainty models without analysis of the actual data is not adequate. The following items should be investigated by a borehole surveying specialist in conjunction with the service contractor supplying the instrument;

- Type of instrument
- Geographic location, borehole attitude
- Instrument uncertainty model
- Calibration data
- Field quality control
- Field data analysis
- Survey comparisons

Number of Relief Wells

Several factors must be considered when planning the number of relief wells to start. Technical and economic considerations are influenced by the required hydraulics to regain control of the blowout, high relative position uncertainty between the wells, and a high probability of encountering time delay problems during the course of the project.

These factors may technically require more than one well, or it may be an economic risk decision. That is, will the increased cost of a second well out-weight the risk of possible long delays or the complete loss of a single relief well?

Historically, the execution of two redundant, simultaneous and independent intervention projects has normally proven sufficient. If a surface intervention is undertaken, and has a reasonable chance of success, then a single relief well may be adequate. If serious pollution or other environmental damage is being caused by the blowout, two relief wells might be considered regardless of the surface intervention plans.

Initial Casing Search Depth

The items normally evaluated in establishing this point are;

- Type of search instrument

- Blowout tubular and sidetracked fish
- Formation characteristics
- Type of drilling fluid
- Relative position uncertainty
- Formation drill ability near detection point
- Well control considerations
- Well path and dogleg considerations

Relief Well Geometry

With the kill point, casing search and cross point, and surface location fixed, detailed directional planning can commence. The following items are normally considered in the relief well geometry.

- KOP, build, drop, and turn rates
- Formation consideration
- Well control/lost circulation
- Casing detection considerations
- Survey accuracy considerations
- Torque, drag, and casing wear
- Hole sizes and casing points
- Kill point approach angle.

Documentation and Audit Trail

If the blowout intervention operation develops into a major project with many people and organizations involved, both within and outside the company, control of critical documents can be very important.

This information will be required later by the insurance companies, regulatory bodies, upper management, and auditors, etc., not to mention future value as a training tool. It is even more important during the project to assure all well data is transferred properly, important operational steps are not omitted, engineering work is checked, written communication is properly distributed, confidential material is protected, and the meeting minutes are properly documented.

Under these circumstances, it is recommended to assign someone full-time to manage this task. This should be assigned to someone, preferably an engineer, who understands what is taking place, and should not arbitrarily be assigned to a secretary.

NON-STEERABLE DRILLING TOOLS

The drilling tools required to drill the relief well may vary somewhat depending on the exact requirements and availability at the time. Listed in Tables A.1, A.2 and A.3 are general listings to be used as a guide in preparation for drilling the relief well when using non-steerable systems (which may not be available in the region).

Table A.1: 17-1/2" Phase, Non-Steerable Directional Drilling Tools

Item	Qty	Size	Description	Connections (Up x Down)
1	2	9-5/8"	Down Hole Motor	7-5/8" Reg B x 7-5/8" Reg B
2	2	9-1/2"	Short Drill Collar (0.50m)	7-5/8" Reg B x 7-5/8" Reg P
3	1	9-1/2"	Short Drill Collar (0.90m)	7-5/8" Reg B x 7-5/8" Reg P
4	1	9-1/2"	Short Drill Collar (1.50m)	7-5/8" Reg B x 7-5/8" Reg P
5	1	9-1/2"	Short Drill Collar (2.0m)	7-5/8" Reg B x 7-5/8" Reg P
6	1	9-1/2"	Short Drill Collar (4.0m)	7-5/8" Reg B x 7-5/8" Reg P
7	1	9-1/2"	Short Drill Collar (6.0m)	7-5/8" Reg B x 7-5/8" Reg P
8	2	17-1/2"	Integral Blade Near Bit Stabilizer	7-5/8" Reg B x 7-5/8" Reg P
9	3	17-1/2"	Integral Blade String Stabilizer	7-5/8" Reg B x 7-5/8" Reg P
10	2	17-1/4"	Integral Blade String Stabilizer	7-5/8" Reg B x 7-5/8" Reg P
11	1	17"	Integral Blade String Stabilizer	7-5/8" Reg B x 7-5/8" Reg P
12	1	9-1/2"	Bent Sub – 2-1/2 degree	7-5/8" Reg B x 7-5/8" Reg P
13	1	9-1/2"	Bent Sub – 2-1/4 degree	7-5/8" Reg B x 7-5/8" Reg P
14	1	9-1/2"	Bent Sub – 2 degree	7-5/8" Reg B x 7-5/8" Reg P
15	1	9-1/2"	Bent Sub – 1-3/4 degree	7-5/8" Reg B x 7-5/8" Reg P
16	2	9-1/2"	Circulating Sub	7-5/8" Reg B x 7-5/8" Reg P
17	2	9-1/2"	Float Sub	7-5/8" Reg B x 7-5/8" Reg P
18	2	9-1/2"	MWD	7-5/8" Reg B x 7-5/8" Reg P
19	2	9-1/2"	UBHO Sub	7-5/8" Reg B x 7-5/8" Reg P
20	1	17"	Melon Stabilizer	7-5/8" Reg B x 7-5/8" Reg P
21	2	9-1/2"	Mandrel String Stabilizer	7-5/8" Reg P x 7-5/8" Reg P
22	5	Assort.	Sleeves	7-5/8" Reg B x 7-5/8" Reg P

Table A.2: 12-1/4" Phase, Non-Steerable Directional Drilling Tools

Item	Qty	Size	Description	Connections (Up x Down)
1	2	9-5/8"	Down Hole Motor	7-5/8" Reg B x 7-5/8" Reg B
2	2	9-5/8"	9-5/8" XO PDM	6-5/8" Reg B x 7-5/8" Reg P
3	1	8"	Down Hole Motor	6-5/8" Reg B x 6-5/8" Reg B
4	2	8"	Short Drill Collar (0.50m)	6-5/8" Reg B x 6-5/8" Reg P
5	1	8"	Short Drill Collar (0.90m)	6-5/8" Reg B x 7-5/8" Reg P
6	1	8"	Short Drill Collar (1.50m)	6-5/8" Reg B x 6-5/8" Reg P
7	1	8"	Short Drill Collar (2.0m)	6-5/8" Reg B x 7-5/8" Reg P
8	1	8"	Short Drill Collar (4.0m)	6-5/8" Reg B x 6-5/8" Reg P
9	1	8"	Short Drill Collar (6.0m)	6-5/8" Reg B x 7-5/8" Reg P
10	2	12-1/4"	Integral Blade Near Bit Stabilizer	6-5/8" Reg B x 6-5/8" Reg B
11	4	12-1/4"	Integral Blade String Stabilizer	6-5/8" Reg B x 7-5/8" Reg P
12	2	12"	Integral Blade String Stabilizer	6-5/8" Reg B x 6-5/8" Reg P
13	1	11-3/4"	Integral Blade String Stabilizer	6-5/8" Reg B x 7-5/8" Reg P
14	1	11-7/8"	Melon Stabilizer	6-5/8" Reg B x 6-5/8" Reg P
15	1	11-3/4"	Melon Stabilizer	6-5/8" Reg B x 7-5/8" Reg P
16	1	8"	Bent Sub – 2-1/2 degree	6-5/8" Reg B x 6-5/8" Reg P
17	1	8"	Bent Sub – 2 degree	6-5/8" Reg B x 7-5/8" Reg P
18	1	8"	Bent Sub – 1-3/4 degree	6-5/8" Reg B x 6-5/8" Reg P
19	1	8"	Bent Sub – 1-1/2 degree	6-5/8" Reg B x 7-5/8" Reg P
20	1	8"	Bent Sub – 1-1/4 degree	6-5/8" Reg B x 6-5/8" Reg P
21	2	8"	Circulating Sub	6-5/8" Reg B x 7-5/8" Reg P
22	2	8"	Float Sub	6-5/8" Reg B x 6-5/8" Reg P
23	2	8-1/8"	MWD	6-5/8" Reg B x 7-5/8" Reg P
24	2	8"	UBHO Sub	6-5/8" Reg B x 6-5/8" Reg P

Table A.3 : 8-1/2" Phase, Non-Steerable Directional Drilling Tools

Item	Qty	Size	Description	Connections (Up x Down)
1	2	6-1/2"	Down Hole Motor	4" IF B x 4" IF P
2	2	6-1/2"	Short Drill Collar (0.50m)	4" IF B x 4" IF P
3	1	6-1/2"	Short Drill Collar (0.90m)	4" IF B x 4" IF P
4	1	6-1/2"	Short Drill Collar (1.50m)	4" IF B x 4" IF P
5	1	6-1/2"	Short Drill Collar (2.0m)	4" IF B x 4" IF P
6	1	6-1/2"	Short Drill Collar (4.0m)	4" IF B x 4" IF P
7	1	6-1/2"	Short Drill Collar (6.0m)	4" IF B x 4" IF P
8	2	8-1/2"	Integral Blade Near Bit Stabilizer	4" IF B x 4-1/2" Reg B
9	4	8-1/2"	Integral Blade String Stabilizer	4" IF B x 4" IF P
10	1	8-1/4"	Integral Blade String Stabilizer	4" IF B x 4" IF P
11	1	8"	Integral Blade String Stabilizer	4" IF B x 4" IF P
12	1	6-1/2"	Bent Sub – 2-1/2 degree	4" IF B x 4" IF P
13	1	6-1/2"	Bent Sub – 2 degree	4" IF B x 4" IF P

14	1	6-1/2"	Bent Sub – 1-3/4 degree	4" IF B x 4" IF P
15	1	6-1/2"	Bent Sub – 1-1/2 degree	4" IF B x 4" IF P
16	2	6-1/2"	Circulating Sub	4" IF B x 4" IF P
17	2	6-1/2"	Float Sub	4" IF B x 4" IF P
18	2	6-1/2"	MWD	4" IF B x 4" IF P
19	2	6-1/2"	UBHO Sub	4" IF B x 4" IF P
20	1		Portable Computer	4" IF B x 4" IF P

10.8.6 Steerable Drilling Tools

The drilling tools required to drill the relief well may vary somewhat depending on the exact requirements and availability at the time. List in Tables A.4, A.5 and A.6 are general listings to be used as a guide in preparation for drilling the relief well when using steerable systems (which may not be available in the region).

Table A.4 : 17-1/2" Phase, Steerable System Tools, 5° – 6° /100'

Item	Qty	Size	Description	Connections (Up x Down)
1	2	9-5/8"	Steerable Motor, 0-3° Adjustable	7-5/8" Reg B x 7-5/8" Reg B
2	2	9-1/2"	Non-magnetic Drill Collars (10.0m)	7-5/8" Reg B x 7-5/8" Reg P
3	3	9-1/2"	Drill Collars (10.0m)	7-5/8" Reg B x 7-5/8" Reg P
4	2	9-1/2"	Short Non-magnetic Drill Collars (3.0m)	7-5/8" Reg B x 7-5/8" Reg P
5	2	17-1/2"	Integral Blade Near Bit Stabilizer	7-5/8" Reg B x 7-5/8" Reg B
6	4	17-1/4"	Integral Blade String Stabilizer	7-5/8" Reg B x 7-5/8" Reg P
7	1	17-1/4"	Integral Blade String Stabilizer	7-5/8" Reg B x 7-5/8" Reg P
8	1	17"	Monel Integral Blade String Stabilizer	7-5/8" Reg B x 7-5/8" Reg P
9	2	9-1/2"	Circulating Sub	7-5/8" Reg B x 7-5/8" Reg P
10	2	9-1/2"	Float Sub	7-5/8" Reg B x 7-5/8" Reg P
11	2	9-1/2"	MWD	7-5/8" Reg B x 7-5/8" Reg P
12	2	9-1/2"	UBHO Sub	7-5/8" Reg B x 7-5/8" Reg P
13	1	17"	Melon Stabilizer	7-5/8" Reg B x 7-5/8" Reg P
14	2	9-1/2"	Mandrel String Stabilizer	7-5/8" Reg P x 7-5/8" Reg P
15	5	Assort.	Sleeves	7-5/8" Reg B x 7-5/8" Reg P

Table A.5 : 12-1/4" Phase, Steerable System Tools, 11° – 12° /100'

Item	Qty	Size	Description	Connections (Up x Down)
1	2	9-5/8"	Steerable Motor, 0-3° Adjustable	7-5/8" Reg B x 7-5/8" Reg B
2	2	9-5/8"	9-5/8" XO PDM	6-5/8" Reg B x 7-5/8" Reg P
3	1	8"	Steerable Motor, 0-3° Adjustable	6-5/8" Reg B x 6-5/8" Reg B
4	2	8"	Non-magnetic Drill Collars (10.0m)	6-5/8" Reg B x 6-5/8" Reg P
5	2	8"	Non-magnetic Drill Collars (3.0m)	6-5/8" Reg B x 7-5/8" Reg P
6	3	8"	Drill Collars (10.0m)	6-5/8" Reg B x 6-5/8" Reg P
7	1	8"	Short Non-magnetic Drill Collars (3.0m)	6-5/8" Reg B x 7-5/8" Reg P
8	2	12-1/4"	Integral Blade Near Bit Stabilizer	6-5/8" Reg B x 6-5/8" Reg P
9	4	12-1/4"	Integral Blade String Stabilizer	6-5/8" Reg B x 7-5/8" Reg P
10	2	12"	Integral Blade String Stabilizer	6-5/8" Reg B x 6-5/8" Reg B
11	1	11-3/4"	Monel Integral Blade String Stabilizer	6-5/8" Reg B x 7-5/8" Reg P
12	1	11-7/8"	Melon Stabilizer	6-5/8" Reg B x 6-5/8" Reg P
13	1	11-3/4"	Melon Stabilizer	6-5/8" Reg B x 7-5/8" Reg P
14	2	8"	Circulating Sub	6-5/8" Reg B x 6-5/8" Reg P
15	2	8"	Float Sub	6-5/8" Reg B x 7-5/8" Reg P
16	2	8-1/8"	MWD	6-5/8" Reg B x 6-5/8" Reg P
17	2	8"	UBHO Sub	6-5/8" Reg B x 7-5/8" Reg P

Table A.6 : 8-1/2" Phase, Steerable System Tools

Item	Qty	Size	Description	Connections (Up x Down)
1	2	6-1/2"	Steerable Motor, 0-3° Adjustable	4" IF B x 4" IF B
2	2	6-1/2"	Non-magnetic Drill Collars (10.0m)	4" IF B x 4" IF P
3	3	6-1/2"	Drill Collars (10.0m)	4" IF B x 4" IF P
4	2	6-1/2"	Drill Collars (3.0m)	4" IF B x 4" IF P
5	1	6-1/2"	Short Non-magnetic Drill Collars (3.0m)	4" IF B x 4" IF P
6	2	8-1/2"	Integral Blade Near Bit Stabilizer	4" IF B x 4-1/2" Reg B
7	4	8-1/2"	Integral Blade String Stabilizer	4" IF B x 4" IF P
8	1	8"	Monel Integral Blade String Stabilizer	4" IF B x 4" IF P
9	2	6-1/2"	Circulating Sub	4" IF B x 4" IF P
10	3	6-1/2"	Float Sub	4" IF B x 4" IF P
11	2	6-1/2"	MWD	4" IF B x 4" IF P
12	2	6-1/2"	UBHO Sub	4" IF B x 4" IF P
13	1		Portable Computer	

10.8.7 Pumping Speeds

The worst horsepower case must be determined from the runs made with the dynamic two-phase flow simulator for a surface blowout flow, assuming that the design rate is 57.3 barrels per minute at 740 psi surface pumping pressure. The piping and discharge pressure specification for kill equipment shall be 5,000 psi. The 5000 psi rating is chosen because this is the minimum rating to be considered for any relief well pump job and secondly it is minimum rating commonly available

from pumping vendors. Horsepower is determined by rating of units rather than equating horsepower alone. The recommended method is per Equation A.1 shown below. Example A.1 shows that a minimum safety factor or 1.5 for pumping is recommended. Therefore, if a discharge of 750 psi is anticipated the required horsepower would be 8 units or 612 HP each for a total of 4896 HP (612 HP is the 100% rating for an HT-400 used in the example). If one were to use a simplified approach where HP is merely pump discharge pressure time rate the calculations would yield only a minimum of 1040 horsepower without SF and 1560 HP with a 1.5 SF. There is significant difference in these calculations, because pure horsepower calculation does not take into account the pump limitations (liner rating, strokes per minute limits, etc.). Some cases may require more pump rate, but these are usually accompanied with low flowing bottom hole pressures. This condition required less hydraulic horsepower. For safety and reliability, it is recommended that external stand-alone, independent drive pumps (DS Schlumberger, Halliburton, etc.) be provided in all cases. For purposes of discussion in this report Halliburton pump specifications have been used (not as a recommended vendor for these services although they are very capable, but because the author is more familiar with their equipment). If competing vendors are chosen, their equipment will be comparable and little modification except review of pressure-volume characteristics will be required. Figure H.4. shows this pumping spread for 8 each 600+ HP pumps.

The methods for specifying the hydraulic horsepower and numbers of units required to achieve the required injection pressure use the predicted pressure and pumping volumes from a two-phase flow model (for example DYN-X). Rather than applying a multitude of safety factors to each individual input value that affects the pumping requirements, the maximum theoretical values are used. Allowances are made for leakoff of fluid to the open hole (for example 10%) and calculations should be made to determine the numbers of units required for a given scenario. All these calculations should be done without applying safety factors and then an overall safety factor applied. The basis for calculating the required pumps follow;

Equation A.1

$$N_p = \frac{Q_k}{(1 - LO)} \frac{SF}{Q_u}$$

Where:

N_p =number of pump units (round to integer)

Q_k =design kill rate, [bpm]

SF=safety factor [°]

Q_u =max. Flow per unit, [bpm per unit] from manufacturer's data for 100% performance at anticipated discharge pressure (see Fig. H.5)

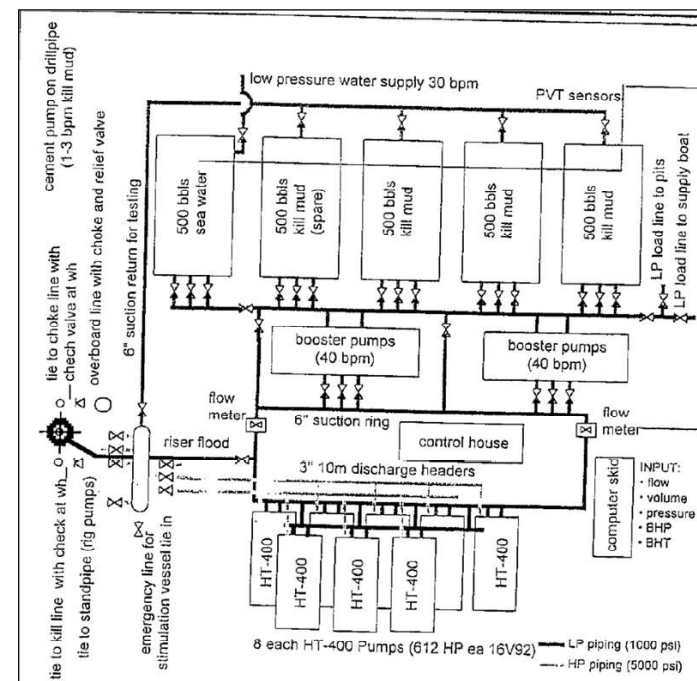


Figure H.4 Example Relief Well Pump Spread (Offshore)

Example

For Exploration type wells analysed using a two-phase dynamic kill model, 57.3 BPM kill rate was determined (maximum for 12-1/4" drilling phase). The maximum discharge from the pressure loss model is 740 psi (rounded to nearest 10 psi). From Figure H.5 the PVC discharge yields maximum available rate per unit, Q_u , of 12.5 barrels per minute per unit if maximum horse power is expended. Assuming 10% leakoff to the formation during the kill operation, LO becomes 0.10 given that the overall safety factor, SF, is 1.50. For this scenario, the required number of pumps will be;

$$N_p = 57.3 / (1 - 0.2) \times 1.5 / 12.5$$

$$N_p = 7.64 \text{ say } 8 \text{ units rounded to the nearest integer}$$

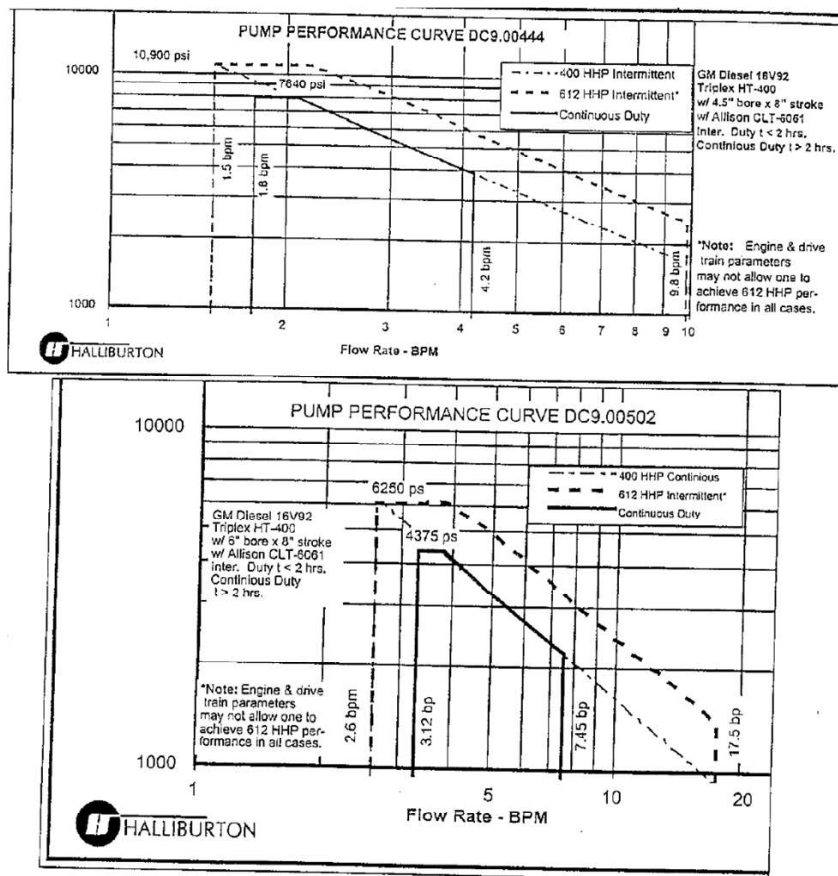


Figure H.5 Pressure Volume Curve
(Courtesy of Halliburton Energy Services, Duncan, OK)

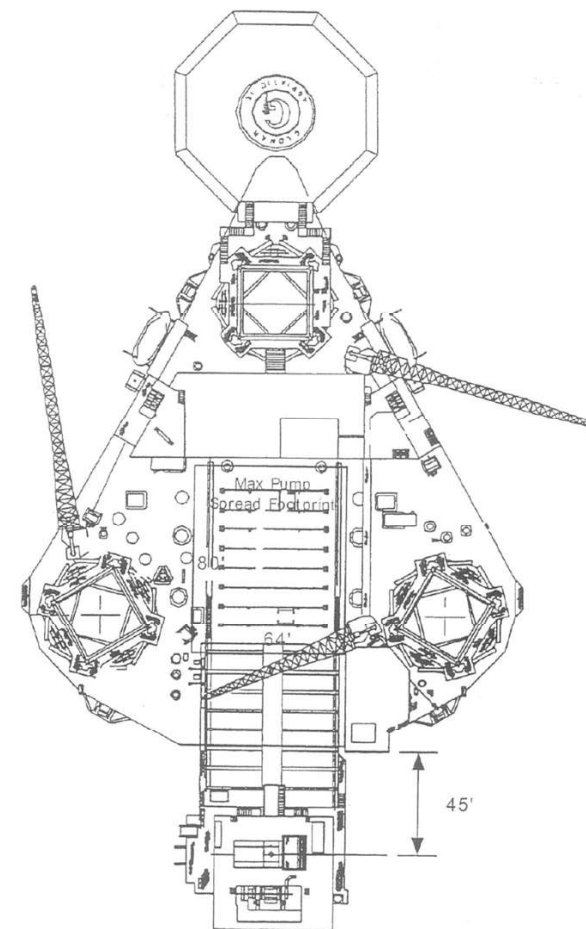


Figure H.6

10.8.8 CONCLUSION

The conclusion to be drawn is that the relief well can in fact be drilled to an interception of the blowout well with great confidence. Further, the directional and proximity drilling technology has advanced so that a wellbore interception is now the rule instead of the exception. While a relief well is necessary to control only a minor portion of blowout wells, it is a viable option in those situations where surface intervention is not a workable alternative.

10.9 RELIEF WELL STRATEGY

This discussion provides site specific details necessary for drilling a relief well in the Gulf of Thailand. It assumes the blowout is from a well that has penetrated the main producing interval of a development, delineation or exploration well. This section contains site specific relief well details while Appendix D contains the generic guidelines. (Note: Appendix D can be found in Volume II). Relief wells are not usually considered for the solution of shallow gas blowouts therefore this is not addressed in this plan.

10.9.1 Relief Well Target

The relief well will be aimed for an intercept of the blowout well as near to the source of the blowout as possible. For planning purposes in this report the target used to design trajectories is the top perforation in development wells and the top of the producing interval in drilling wells.

If the drill string is not in the hole or across the primary interval, an upper target must be selected based on the location of pipe or casing in the well. The worst case would be an interception target in the open hole that is void of pipe (casing or drill pipe). This would require the relief well to be aimed at the last casing shoe set, the 13-3/8" or 9-5/8" casing shoes for the 12-1/4" or 8-1/2" phases.

For this report the coordinate system at the surface is referenced to the surface location of the target well and UTM coordinates.

10.9.2 Positioning the Relief Well

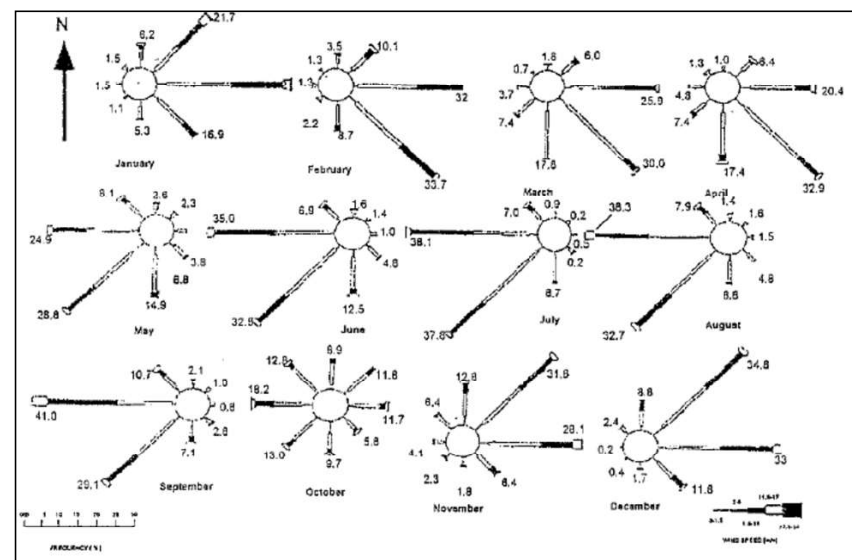
Positioning the relief well involves a number of objective and subjective considerations. Listed below are the factors taken into account for safe positioning of a relief well:

- Maintain at least a 300 m clearance from the blowout well surface location if the relief well is located in the SE quadrant (see figure I.3).
- Maintain a 600 m clearance from the blowout well surface location if the relief well is located in any quadrant other than the SE.
- Avoid the current gas dispersion streams by positioning the relief well where the Lower Explosive Limits 'LEL' of 5% by volume are within acceptable limits at every possible wind condition.
- Avoid seafloor obstructions in area; anchor pattern to leave 50 m of clearance from any obstruction (pipelines, flowlines, umbilicals, etc.).
- Avoid shallow gas zones that can be drilling hazards per the discussion of Section C.4 also see hazard map and relief well position for Bongkot platforms according to shallow gas hazard in Section 8).
- A position that accounts for favorable winds so that the relief well is upwind most of time. The major factors are the time of year and the time that will be required to drill the well Note: This will have to be determined on the fly and is not specifically addressed in this report.

The SE quadrant shown in Figure I.3 is the preferred all weather relief well position relative to the blowout. This is chosen as the position that is most likely to be upwind the majority of the time. The exception is the month of October when the winds are light and variable. Gas dispersion modelling has been done which indicates that the 300 meter distance is acceptable for the October wind conditions. IF necessary the relief well can be positioned downwind, but distance from the blowout must be increased to 600 m. The basis for this is taken from gas dispersion modelling where the blowout rates were used to determine LEL for the worst case wind conditions (slight

breeze and a subtropical inversion reducing natural mixing of the air). More detail of the gas dispersion analysis can be found in Section G.5. Figures I.1 and I.2 show the wind roses used to make this determination and the result of the gas dispersion analysis.

If may be possible to position a well inside the exclusion zone, but this will need to be based on actual conditions (e.g. air quality monitoring). Choosing a location not meeting the above conditions can only be done if conditions at the blowout location do not jeopardize the drilling crew or equipment safety. If the risk is excessive, then the alternative profiles (Double-S to vertical shapes) should be chosen for the relief wells.



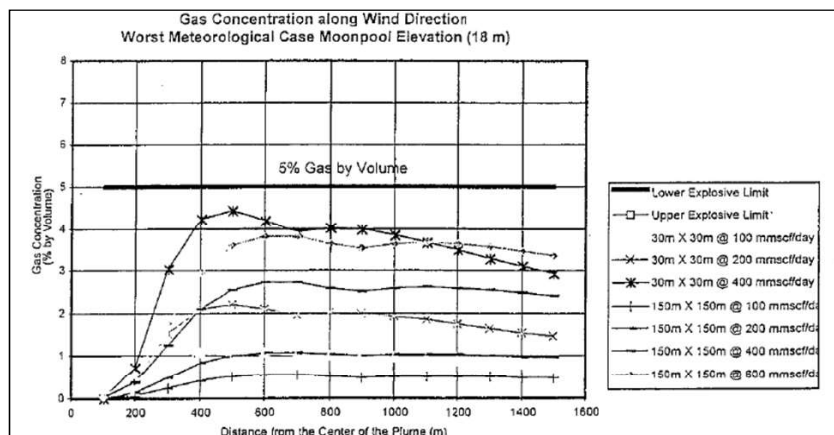


Figure 2 Gas Dispersion Analysis Summary

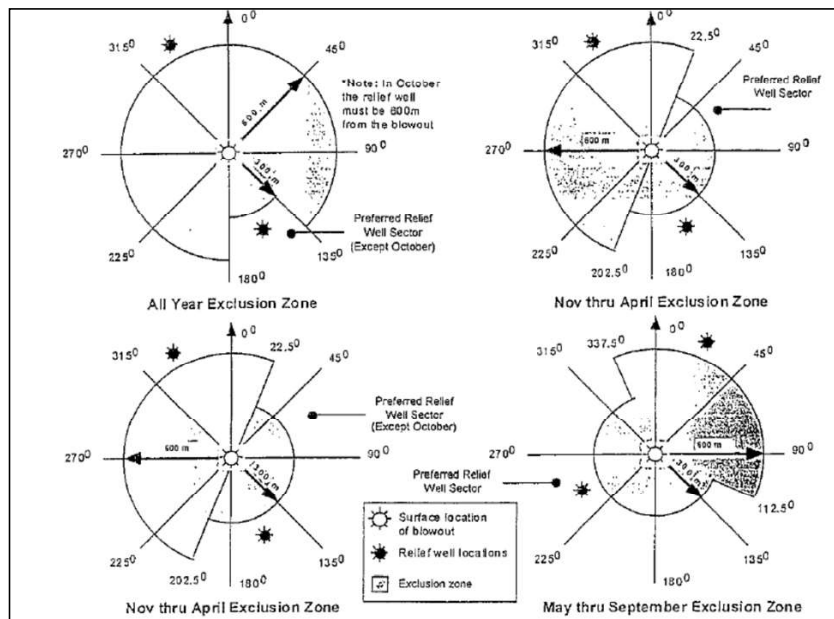


Figure I.3 Exclusion Zone for Relief Well Placement

10.9.3 Relief Well Trajectory

The relief wells are designed to have the relief well lined up at least 100 m before reaching the target and to have no more than 10 degrees of combined azimuth and inclination difference from the blowing well at the intercept point. The relief wells should come within the effective range of the proximity tools (25 to 50 m displacement) at the first detection point and approximately 150 m before drilling to the target (e.g. reservoir penetration or last casing shoe). When within this range, the proximity tools will be run to locate the target and direct the relief well to this revised target. The azimuth direction will be approximately the same as the blowing well. A slight lead to the left is preferred in order to allow the well to turn to the right and drop angle as the final corrections are made to the target (about 5 to 10 degrees will be adequate to meet this criteria). For purposes of design and to account for some right-hand walk a 6 degree lead angle has been chosen for planning purposes.

The simplest and shortest drilling distance for the relief well was chosen whenever possible. This is a simple build and hold (J-curve) trajectory. For a J-curve, the surface location is placed for the minimum required displacement, therefore minimum linear drilling distance. This is the chosen relief well plan for the intercept. The first detection target is the blowout well at a point approximately at the reservoir penetration.

The logic for presenting these minimum displacement locations is to have the option to minimize the relief well drilling effort should a blowout occurs during a period of the year when historic wind conditions are favorable. Also, if the well is blowing out underground and no slick was anticipated or being generated the distance to blowout surface location may not be factor.

J-curve (build and hold) and S-curve

Relief well trajectories designed for this project were put into three (3) categories and are summarized below:

- Relief Well A – J curve build and hold positioned at least 600 m from the blowout platform location.
- Relief Well B-S-curve to vertical positioned 300 or 600 m from the blowout bottom hole location. These would be the relief wells needed for a vertical well blowing out on a platform or a floating rig. Two cases are considered for a development well and an exploration well.
- Relief Well C-A vertical well positioned at least 600 m from the blowout platform location. This would cover the relief well needs of wells BK-4-D, F, G and L along with BK-6-A and D. These wells are S-curve wells with the bottom hole portion of the well at least 600 m from the platform. The wells are assumed to be close to vertical at the top of reservoir, which would allow a vertical relief well to be drilled.



Table I.1 gives the surveying data and ties for the relief wells mentioned above.

Well	Top Perf m TVD	Top Perf UTM N	Location UTM E	Angle deg	Azimuth deg	Displ to plat	Direction from plat	Relief Plan	Well Displ	RW UTM N	Sur Loc UTM E	RW Displ to Plat	No te
BK-1-B	1308	889,175	865,899	38.76	323.96	387	358.13	37	176	889,279	865,803	479	*
BK-1-C	1415	889,592	865,041	49.65	355.67	651	22.83	8E	248	889,811	865,380	876	
BK-1-E	2048	888,632	865,516	32.25	58.52	220	231.34	30	127	888,544	865,408	402	*
BK-1-D	1493	888,518	866,783	25.41	109.04	1111	105.14	25	96	888,427	866,592	1053	
BK-1-F	1502	888,862	865,574	31.65	294.24	147	291.51	30	127	888,978	865,690	171	*
BK-1-G	1433	887,985	865,700	45.82	184.21	823	180.77	6E	248	888,003	865,718	805	
BK-1-H	1458	888,953	866,871	43.65	82.69	1169	82.87	6E	248	888,707	866,825	920	
BK-1-K	1789	886,109	865,237	5.82	98.35	848	214.14	Vert	0	888,109	865,237	845	
BK-1-L	1368	886,359	866,123	18.52	89.98	612	137.71	13	37	886,318	866,066	617	
BK-1-M	963	887,814	866,023	59.88	164.00	1042	162.57	5C	454	887,678	865,887	1144	
BK-2-A	1531	885,137	868,324	56.70	304.10	1241	340.71	6B	332	885,412	868,599	1453	
BK-2-B	1532	884,091	867,821	52.74	271.73	921	277.82	6B	332	884,423	868,163	739	
BK-2-C	1418	883,900	869,352	35.53	196.00	622	96.07	30	127	883,935	869,387	654	
BK-2-D	1434	882,589	869,604	52.14	85.09	870	88.47	5E	248	883,741	869,356	652	
BK-2-E	1950	883,458	868,208	40.13	224.39	752	224.36	37	176	883,581	868,321	678	*
BK-2-F	1318	883,255	868,175	43.45	206.92	902	217.58	37	176	883,335	868,259	750	
BK-2-G	1515	882,782	869,324	54.54	177.02	1323	153.50	6B	332	882,785	869,307	1331	
BK-2-H	1278	883,285	869,381	53.66	139.26	935	135.45	6B	332	883,068	869,154	995	
BK-2-K	1519	883,194	868,040	39.15	157.04	839	158.52	37	176	883,115	868,971	883	
BK-2-J	1476	884,028	866,508	49.88	269.65	2227	271.55	6E	248	884,274	866,756	2002	
BK-2-L	1343	884,127	867,417	58.20	277.28	1327	275.96	6B	332	884,456	867,746	1103	
BK-2-M	1365	882,951	867,319	51.82	238.15	1741	234.35	6E	248	883,157	867,525	1455	
BK-3-A	1515	887,976	867,055	57.15	288.29	1277	266.05	6B	332	888,291	867,390	965	
BK-3-B	1529	888,334	867,528	39.01	291.51	854	288.43	37	176	888,506	867,700	777	
BK-3-C	1549	888,941	868,837	37.21	48.51	763	40.81	37	176	888,509	868,705	977	*
BK-3-D	1551	888,877	869,585	58.73	58.83	1498	58.89	6B	332	888,569	869,307	1107	
BK-3-E	1490	887,511	867,228	49.73	258.13	1241	243.54	6E	248	887,754	867,471	922	
BK-3-F	1448	887,757	867,819	24.92	241.79	804	235.49	25	96	887,842	867,903	489	*
BK-3-G	1453	887,919	868,092	13.72	328.39	286	238.58	13	37	887,938	868,111	360	*
BK-3-K	1436	887,192	867,501	58.74	264.50	975	265.85	6B	332	887,330	868,030	763	
BK-4-D	1542	895,099	863,163	48.54	32.39	951	52.00	6E	248	894,903	852,957	566	
BK-4-H	1459	894,465	863,041	38.99	90.38	647	93.76	37	176	894,229	862,865	518	*
BK-4-G	968	894,359	862,615	45.75	123.88	265	124.11	6E	248	894,153	862,409	355	*
BK-4-F	1407	895,026	861,767	16.27	306.93	815	309.51	13	37	895,054	861,795	812	
BK-4-K	1581	893,714	861,535	46.99	194.99	1171	227.33	6E	248	893,778	861,589	1080	
BK-4-L	934	894,176	852,595	60.36	147.17	387	148.87	6B	332	893,996	862,416	512	*



Well	Top Perf m TVD	Top Perf UTM N	Location UTM E	Angle deg	Azimuth deg	Displ to plat	Direction from plat	Relief Plan	Well Displ	RW UTM N	Sur Loc UTM E	RW Displ to Plat	No te
BK-5-B	2041	888,437	861,957	60.2	341.81	2,275	345.9	6D	519	887,980	862,161	6562	
BK-5-C	1534	897,141	854,894	83.1	67.60	2,404	67.5	63	560	896,884	854,198	7834	
BK-5-D	2120	895,385	864,325	54.97	112.73	2,031	114.3	6E	448	895,249	863,999	9379	
BK-5-E	1320	896,761	862,184	40.34	5.02	612	28.3	40	269	896,492	862,179	5019	
BK-5-F	1584.7	884,993	862,426	50.84	159.23	1,229	2.2	6E	384	884,838	862,255	9970	
BK-5-G	1518.9	886,199	862,589	31.95	125.87	108	61.5	32	183	886,075	862,412	8432	
BK-5-H	940	886,095	862,982	80.92	104.85	535	108.1	6B	529	885,995	862,461	8543	
BK-5-I	1320	886,196	862,311	38.89	51.72	164	8.0	38	253	886,140	862,065	8374	
BK-5-K	2032	885,039	862,790	47.97	164.29	1,224	166.0	6E	358	884,704	862,563	9907	
BK-5-L	1624	883,710	862,406	90.79	176.00	2,512	176.5	6B	527	883,187	862,342	11320	
BK-5-M	2329	884,755	864,048	37.27	125.44	2,144	132.8	37	236	884,645	863,844	9968	
BK-6-A	1591	879,428	870,511	52.64	232.29	1697	233.15	6E	248	879,624	870,707	1423	
BK-6-B	1432	885,703	870,854	55.07	283.48	1007	284.37	6B	332	881,026	871,187	965	
BK-6-C	1214	881,825	871,141	68.33	328.46	1560	332.19	6C	494	882,083	871,399	1704	
BK-6-D	1375	881,102	872,217	30.47	30.50	743	27.56	30	127	881,038	872,153	657	
BK-6-E	1395	879,805	871,356	42.98	214.05	795	216.46	6E	248	879,945	871,535	602	
BK-6-F	1588	880,485	871,475	38.97	273.11	394	272.97	37	176	880,542	871,651	293	*
BK-6-G	1353	880,290	872,436	47.95	106.20	590	105.28	6E	248	880,282	872,200	515	*
BK-6-H	1455	880,282	871,771	33.65	223.79	191	210.82	30	127	880,370	871,859	76	*
BK-6-J	1835	881,285	870,828	44.94	257.20	1337	308.89	6E	248	881,522	871,065	1343	
BK-6-M	971	879,971	872,089	48.18	154.04	523	155.09	6E	248	879,882	871,983	594	*
BK-7-B	1857.4	888,284	874,780	50	323.77	2,326	301.54	6D	516	887,876	875,121	1819	
BK-7-E	2331.3	887,218	874,516	44.91	271.82	1,751	327.71	6E	321	887,539	874,499	1955	
BK-7-F	2036.6	885,292	875,355	39.51	269.61	642	359.12	6E	264	885,555	875,330	721	
BK-7-G	1611.5	885,240	875,946	12	227.20	66	230.50	vert	40	885,266	875,916	300	*
BK-7-H	1650	885,199	876,120	39.73	123.90	149	124.07	6E	262	885,369	875,994	313	*
BK-7-L	1591.2	884,720	876,079	60.21	213.38	1,594	183.00	6B	519	884,567	875,622	1367	
BK-8	Later												
BK-9	Later												
BK-10	Later												
Platform	Location	North	East							North	East		
	WP1	889,908.00	855,711.00							WP6	880,545.60	871,868.60	
	WP2	883,965.70	858,133.90	Platform Location						WP7	886,282	875,997	
	WP3	888,063.80	868,338.60	Platform Location						WP8	888,931	873,025	
	WP4	884,507.43	862,395.85							WP9			
	WP5	888,221	862,473.7							WP10			

Note: Special consideration may be required for these locations due to the time of year and the wind patterns at that time of year.

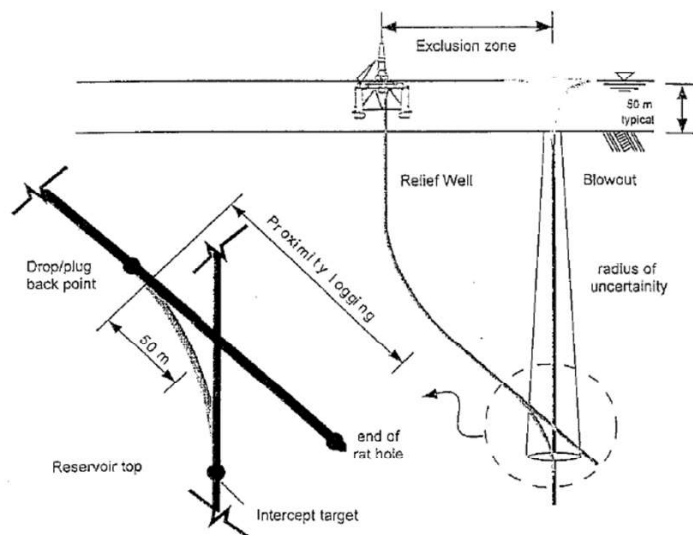


Figure I.4 Type A Relief Wells

10.9.4 Shallow Gas Discussion

As of April 97 the hazard maps for shallow gas for the Bongkot Field and surrounding area is not complete. The mapping done to date has been for the platform areas only. Therefore the choice of locations for the relief wells has ignored the fact that there may be a shallow gas hazard at the optimum location. The optimum location is that position that will yield the minimum lineal footage to reach the target. For example, for high angle wells the relief well location was moved out to a position near the reservoir target. It may well be that these locations are over shallow gas drilling hazards, therefore an investigation must be undertaken before a rig, especially a jack up is moved to drill a relief well. The options for addressing these problems are summarized below:

- If a semi rig is available (either on the market or under contract to PTTEP for exploration during the 1998 exploration campaign), a pilot hole could be drilled riserless to test for the presence of shallow gas.
- Seismic interpretations can be performed for each relief well location (from available data 3-D seismic survey data). This can be done now for all locations chosen for relief wells (perhaps cost prohibitive) or done on a crash program while the rig is being prepared to move onto the relief well location. If the interpretations show a hazard then it can be tested with a pilot hole or an alternative location chosen. Waiting is not seen to have an impact on the timeline to drill the relief well as one can be doing the interpretation while the rig is under tow and other equipment made ready to spud the well. However the window for moving on to the relief well after being given the approval to proceed is approximately 6 days (given there is a rig in the area that can be moved to the Bangkok area). If the interpretation takes more than 6 days it will impact the relief well drilling spud date.

These operational parameters will have to be reviewed if relief well projects become a reality to choose the most expeditious means to drill the relief well given the potential for shallow gas hazard.

10.9.5 Casing Design and Seat Selection

The relief well casing design is the same for a development or exploration type well. This will meet the pumping requirements for the dynamic kill. Additional factors have been considered and evaluated in addressing the relief well design and they are the;

- Effects of well casing configuration on the friction and flow rates required during the kill operation.
- Implications of setting an additional casing string to combat downhole problems encountered during drilling, i.e. can the objective still be attained if a further reduction in hole size is required or addition strings set?
- Realistic possibilities of individual zones being artificially pressured or depleted and is there information to support this position.

In addition to the above, certain questions should be reviewed prior to spudding the relief well to take advantage of the most current information, and these are;

- Has the target location changed significantly since the relief well plan was developed?
- Were there complications encountered in the original blowing well during the up hole sections which could threaten the success of the relief well? How will these be averted?
- Will the casing scheduled have to be modified to meet the directional drilling objectives required to intercept the blowing well?
- Was there an unanticipated presence of a corrosive or toxic fluid such as H_2S that requires special consideration?

Casing Program

The casing program for a development or exploration relief well has taken the above list of considerations into account. The result was basically the same casing program used in the well with one exception; a larger surface casing was used to provide for any contingencies requiring that an additional casing string be run due to hole problems or mechanical difficulties. This is not to say that attenuating circumstances such as an underground flow may require re-evaluation. If unanticipated pressuring of a shallow interval occurs, additional casing may be required. For the purposes of this report, subsurface charging has not been considered because it is believed that the relief well can be spudded and drilled to objective TVD before time dependent charging can become a factor in the shallow horizons. Also, the likelihood of shallow charging is dependent upon having a shallow casing leak, which is a low probability scenario, but should be considered if a relief well becomes a reality.

CAUTION Charging of subsurface zones must be reviewed prior to spudding the relief well to make assurance that it does not represent a drilling hazard.

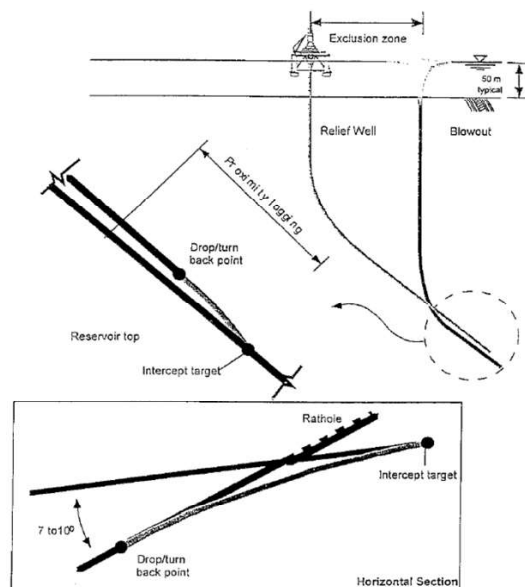


Figure I.5 Relief Wells for Inclined Targets

A 7" liner would not be required under most circumstances unless hole conditions require its use. The author saw no reason to program the 7" liner and 6" open hole to target PTTEP depth, but leaves this as a contingency should it be needed to accomplish the interception. This option would have to be thoroughly evaluated because with its use would come a host of additional problems and limitations. With the 7" liner in place it will be difficult or impossible to plugback the relief well to make directional corrections. Thus the 7" liner will induce additional risks to the relief well should interception or pumping to kill fail in the initial attempts. Table 5.2 shows the recommended casing program for all relief wells.

CAUTION Setting a 7" liner must be done only as a last resort and then only after very careful review. Note that this will certainly limit any future directional correction and severely restrict the flow during the kill operation.

Table I.2 : Relief Well Casing Program

Casing Size	Casing point objective	Casing description	Drift ID. (inches)	Internal Yield
30"	Approx. 60 m. below sea floor	1.5"Wall LYNX-HD		
13-3/8"	Approx. 450 m.	68 ppf N80 Buttress	12.26	5018 psi
9-5/8"	Approx. 1060 m TVD	53.5 ppf 95 grade New Vam	8.525	9410 psi
7" Liner*	To be set only if hole conditions dictate to reach objective	32 ppf 95 grade 0 VAM	5.969	10760 psi

*Note: Only if required by hole conditions.

Well Control Considerations

The blowing well may introduce new pressure environments in the formations through which the relief well must drill. This may be characterized by over pressured or depleted zones.

When considering a surface blowout after the 9-5/8" casing has been set above the reservoir, it is assumed that the integrity of the 9-5/8" casing and casing shoe are maintained and no underground flow has or can occur. Under this scenario, no unusual or abnormal pressures should be encountered above the 9-5/8" casing setting depth in the blowing well. It is believed that drilling of the relief well should proceed according to the program to the 9-5/8" casing point (approximately 1060 m TVD) without major concern.

Before reaching the 9-5/8" shoe all the BOP equipment should be completely tested to the maximum rated pressure and the entire compliment of fully tested kill equipment and kill weight mud should be on hand. From that point forward, precaution must be exercised to control any possible influx. The increased trips necessitated by the directional work will require close control of tripping practices.

Should hole conditions in the relief well deteriorate to the point that progress cannot be made without casing the open hole section, a 7" liner may be set to provide the necessary protection. This should be avoided if possible because it:

- Limits the options for directional correction
- Restricts the use of some directional equipment
- Increases the duration of drilling activity and
- Adds additional friction restrictions for the kill operation.

Should the 7" liner be required, a packoff liner hanger should be installed, and the liner lap dry tested and pressure tested before drilling new open hole.

Subsurface Charging

An underground blowout can cause subsurface charging that can create a drilling hazard for the relief well. If this is the case, careful reservoir modelling will need to be undertaken to determine at what distance the relief well can approach the thief zone without encountering a well kick. Since the relief well target will be the producing zone, this may not be of concern, however careful study is warranted.

The reason for penetrating the blowout reservoir before setting the 9-5/8" casing must be carefully studied before commencing the relief well. Factors such as a thinning of overlying formations or faulting must also be taken into consideration in drilling the relief well.

Before drilling into each zone containing possible abnormal pressures, kill weight mud must be available to control an influx. Tripping practices must be closely monitored with an emphasis on minimal off bottom time. Excessive logging or wiper trips may potentially cause problems (reason for specifying proximity logs to be run inside the drill string rather than in open hole). IF extended periods of logging are required, strong consideration should be given to hole conditioning trips between runs.

Under this scenario, the greatest probability of problems on the relief well would be expected between the 9-5/8" shoe and the interception point. The presence of a high volume underground flow could create a situation that could require the 7" liner. The same complications discussed earlier would be further exacerbated by the requirement for a high rate kill operation.



Operational Comments

As the relief well converges on the blowing well, it is often difficult to anticipate at what point the relief well may begin losing fluids to the blowing wellbore. With this in mind, it must be possible to immediately switch the relief well from drilling to the kill operation at any given time during the final approach to the target wellbore. Therefore, it is imperative that prior to the final approach, all preparations for the kill operation must be complete. In this case, the point at which preparations for the kill operation must be fully completed is before reaching 9-5/8" casing setting depth. Once full wellbore communication is established, the kill operation can continue according to plan.

After locating the target wellbore and before drilling the final segment to interception under either scenario, a trip should be made to remove all unnecessary restrictions, i.e., drill collars, heavy-weight drill collars, subs, etc., from the drill string. In this manner the friction losses inside and outside the drill string will be minimized during the kill operation.

10.9.6 Tool Specifications

Directional Survey Tools

Listed below is the directional survey program recommended for the exploration and delineation type wells

42" Hole Section	Check verticality teledrift
Inside 30" Casing	None
17-1/2" Hole Section	Single shot in the middle of the phase and 1 single shot per trip and one battery tool gyro at the end of the phase
Inside 13-3/8" Casing	None
12-1/4" Hole Section	Single shot in the middle of the phase and 1 single shot per trip and one battery tool gyro at the end of the phase
Inside 9-5/8" Casing	None
8-1/2" Hole Section	Magnetic multishot
Inside 7" Casing	No survey

The directional survey program for the relief well follows the basic plan of the program for the producing wells, except for the additional equipment needed in the event a 7" liner must be set, and 5-7/8" hole must be drilled to interception. Listed below is the recommended program:

42" Hole Section	Check verticality with the MWD at the casing point.
Inside 30" Casing	No survey
12-1/4" Hole Section	Drill with an MWD taking data while circulating after drilling each stand
Inside 9-5/8" Casing	Run a North seeking gyro at 10 m stations to 9-5/8" shoe
8-1/2" Hole Section	Drill with an MWD taking data while circulating after drilling 10 m or use of a proximity steering tool
Inside 7" Liner	If a 7" liner is required run a North seeking gyro at 10 m stations to 300 m above the liner top and tie survey data back to the survey inside the 9-5/8" casing
6" Hole Section	Drill with MWD taking data while circulating at intervals dictated by situation or proximity steering tool.



Drilling Tools: The drilling tools required to drill the relief well may vary somewhat depending on the exact requirements and availability at the time. Please see Appendices: Relief Well Planning for a list of equipment recommended.

10.9.7 Modelling Criteria

For this project the DYN-X computer model was employed to describe the relief well and blowout well scenarios. This model considered two-phase steady state gas and oil flow for various pumping rates. The model took into account the geometry of the well, the inflow performance of the reservoir, reservoir fluids and its non-Newtonian behavior and the rheology of the kill fluid. Both sonic (theoretical maximum) and sub-sonic exit conditions were analysed. The models were developed by Dr. Adam. T. Bourgoynne of Louisiana State University on a consulting basis to ABEL Engineering. The models take into account experimentation at LSU where the exit conditions for gas in large diameter pipes have been observed and mathematical descriptions of the pressure relationships developed. The computer models and the equations used are documented in the text Firefighting and Blowout Control by L. William Abel et al. The model is Microsoft Excel™ spreadsheet (runs on the Mac in Version 5.0 and on a PC in Windows Excel™ Version 5.0).

DYN-X was used to investigate several scenarios of blowout conditions and to establish the kill pumping criteria. In addition to kill requirements, the model was used to predict a gas flow rate based on certain assumptions regarding reservoir parameters.

10.9.8 Blowout Scenarios

There are quite literally an infinite number of scenarios for loss of control of a well, however for planning purposes two general categories were considered:

- an underground blowout or
- a surface blowout (e.g. a leak at the BOP level)

All the investigations undertaken were subsets of these two general categories. Some were run to established boundary conditions. The more reasonable or likely situations are noted. Full reservoir potentials were considered for three scenarios. The geometry variations included drillpipe and drill collars in the hole and out of the hole. For each scenario, the wellbore with the shortest path was considered. For some cases, the wellbore with the longest path was used for comparison. In conjunction with this approach, only those scenarios that are both reasonable and feasible were reported and used for designing the pumping requirements. The results are not considered final and adjustment of the kill requirements is anticipated if an actual relief well project becomes a reality.

From the reasoning above the following scenarios were considered for development and exploration wells:

SCENARIO I:

Well is blowing out through a leak in the BOP stack during the 8-1/2" drilling phase. The flow is from the target reservoir at full reservoir potential. There are no leaks in the open hole or cased interval. The drill string is in the hole as per Figure I.6.

SCENARIO II:

Well is blowing out underground from the reservoir to the shoe to the 13-3/8" casing during the 12-1/4" drilling phase. The flow is from the target reservoir at reduced reservoir potential. The drill string is in the hole per Figure I.7

These scenarios are considered to cover the worst case and likely well conditions if the well does blowout. They are **not** a risk assessment that a blowout is likely to occur. A blowout is considered

a very unlikely probability in the first place, but this probability cannot be reduced to zero, therefore a set of "likely" scenarios has been examined.

Scenarios Commentary

An abbreviated system has been chosen for the description of the various scenarios. This is exhibited in the above scenario descriptions. A Roman numeral system describes the physical geometry and exit condition where I, II and A are the three basic physical geometry's scenarios:

I: 9-5/8" casing set, reservoir penetrated with open hole, BOP leaking, casing holding (not ruptured) and no underground flow.

II: 13-3/8" casing set, reservoir penetrated with open hole, underground flow, BOP and casing holding.

A: Designation means that the drill string is in the hole.

B: Designation means that no drill string is in the hole.

xx mD: Designation means that "xx" millidarcies were considered for the strength of the reservoir.

yy Nm: Designation means that "yy" meters of reservoir penetration were considered.

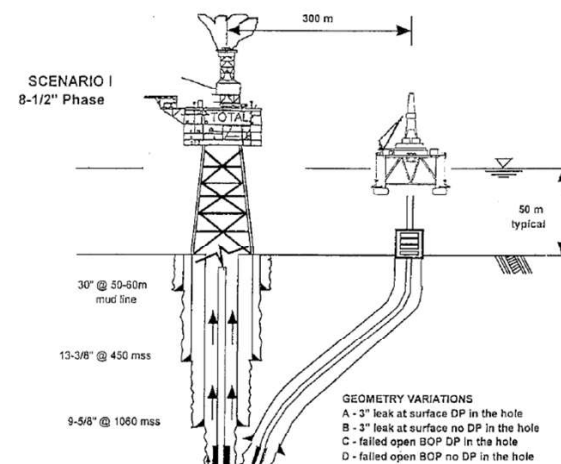


Figure I.6: Scenario I

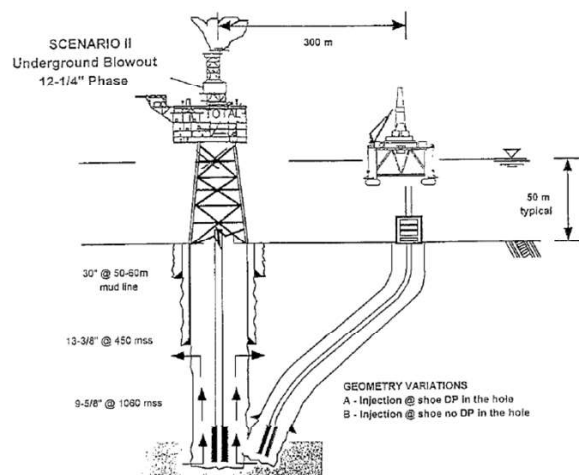


Figure I.7 Scenario II

10.9.9 Kill Fluid Design

Kill Fluid

This report used experience and computer simulations to determine that the most logistically sound kill fluid is a water based drilling mud similar in density to what was used to drill the well. The objective is to slightly overbalance the reservoir pressure, but not fracture the open hole interval during the kill procedure. Note that the kill pump rates calculated will certainly produce an equivalent circulation density that will exceed fracture gradient if not mixed with gas in the wellbore. Therefore, it will be necessary to reduce the pumping rates as the well comes under control to avoid fracturing and leak off of the fluid. Procedural recommendations are contained in a latter section of this report. The kill rheology chosen for the relief well kill operation and computer modelling follows:

Development

- SG = 1.2
- 8-1/2" Hole
- PV = 8 YP = 17
- Fann 600 = 25 Fann 300 = 33

Exploration

- SG = 1.4
- 8-1/2" Hole
- PV = 10 YP = 14

- Fann 600 = 24 Fann 300 = 34

The important factor for the kill fluid rheology is that it has sufficient density to slightly overbalance the reservoir when static but still remain "thin" enough to be pumped at the necessary rates. The properties stated above are not absolute values but reasonable estimates for modelling purposes and estimation of horsepower requirements. These values were taken from the chart shown in Figure C.8. Should a relief well become a reality, the pumping requirements must be reviewed carefully to insure that the actual properties do not exceed the above values by more than 20% as the frictional losses could be significantly larger. Hydraulic calculations for each scenario considered are contained in Appendix E, Section E.3.

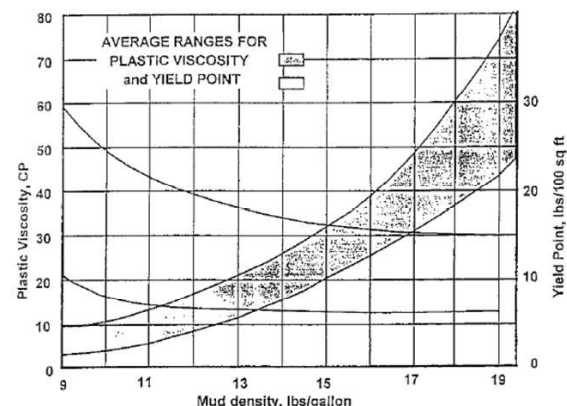


Figure I.8

Fracture Avoidance / Leak Off

During the kill operation when fluid is placed in the blowing well, the objective will be to overcome flowing bottom hole pressure. Thereafter the bottom hole pressure exerted must then slightly overbalance the static reservoir pressure. In no case should the pressure profile in the open hole interval (reservoir to the last casing shoe in the blowing well) be allowed to exceed fracture gradient. If massive fracturing is allowed, the majority of the kill fluid will be lost to the fracture and it is doubtful the well will be killed.

Some leak off will most likely occur during the initial stages of the pump to kill operation. For this report, leak off has been estimated to be 10% of the volume being pumped. Adjustments of the pumping rate have been increased accordingly. For example if the computer model says that 42 barrels per minute is required to kill the well, then 46.2 barrels are modelled for the frictional model.

Fracture avoidance may be very difficult to maintain, but never-the-less it is the most logical and prudent procedure to follow during the kill operation. To this end, the pressure profiles for various pumping rates of kill fluid have been reviewed to see that fracture gradient is not exceeded at the recommended pumping rates. A procedure will need to be developed to prevent fracture of the open hole during the kill operation. DYN-T transient analysis is recommended to the guide actual operation.



10.9.10 Pumping Requirements

Of the scenarios considered, scenario I-A and II-A are more likely to present themselves than scenarios I-B and II-B. Table C.6 contains summaries of the computer investigations. All the computer results are contained in the appendix of this report should more detail be needed.

All other scenarios are considered to be subsets of the above. For kill rates determined to be greater than 50 barrels per minute the scenario were reviewed carefully and all were considered to be either unreasonable or boundary condition and unlikely to occur. In the event that a blowout does occur that matches these models for gas rates and pump rates greater than 50 barrels per minute, multiple relief wells may be needed.

(Kill Pump rates, Pump Spread, FBHP and Blowout Flowrates)

DYN-X		CALCULATED PARAMETERS													
Qgas mmscfd	Coil sid/d	FBHP* psi	Mud Hydro	System Losses	Pump Press	Min HHP	BPM w/LO	SF	Assm'd LO	BBL/Sr Pump	HHP/ pump	Num pumps	actual HHP	Case	
218.7	4374.2	3055.9	-1188	325	1888	1481	31.91	1.5	10%	8	612	6	3672	Dev 3" leak DP	
308.9	6177	2746	-1188	682	1558	1838	48.14	1.5	10%	8	612	9	5506	Dev 3" leak NDP	
384.5	3243	5528	-2155	488	3373	2537	30.69	1.5	10%	8	612	6	3672	Exp 3" leak DP	
583.6	5193	5048	-2155	1099	2892	3413	48.16	1.5	10%	8	612	9	5506	Exp 3" leak DP	
47.9	959	965	-2313	874	-1348	n/a	41.11	1.5	10%	12	612	5	3060	UGBO Dev Norm	
66.1	595	5374	-2155	670	3218	n/a	20.00	1.5	10%	12	612	4	2446	UGBO 9m pen	
254.5	5288	94	-1188	345	-1094	n/a	33.03	1.5	10%	8	612	6	3672	Dev 3" leak DP Horiz	
417.8	8356	149	-1188	730	-1039	n/a	49.99	1.5	10%	8	612	9	5506	Dev 3" leak NDP Horiz	

Table I.3 DYN-X SIMULATION SUMMARY

- *Note: Qgas is the maximum rate possible given the input wellbore geometry, as calculated from DYN-X runs.
- *Note: Negative pump pressure means that the relief well will go on a vacuum when interception is made.

The wellbore geometry along with the contract drilling equipment was modelled in a frictional model. Pressure loss equations were per Preston L. Moore "Drilling Practices where Fann data is used to determine friction at a fluid shear rate. Flowing bottom hole pressures were taken from the computer models described earlier. The kill rate plus a percentage to account for leak off was modelled for flow down the relief well annulus, with the drillpipe held for pressure observations. The design horsepower requirements have a 1.5 safety factor applied. Note that the rates used in the frictional model were increased 10% for leak off. Therefore the gross factor of safety for horsepower is 1.65 times the theoretical values. This safety factor is reasonable when considerations are given to unknown factors, like equipment failures etc. The horsepower requirements are summarized in Table I.3.

The volume anticipated for the kill operation is two hole volumes of the blowout well or about 1500 barrels. This was determined from the computer model and experience. Note that if a relief well is drilled, a transient analysis, DYN-XT, will be needed to refine the pumping requirements for the kill operation. This was not done in this report because it was not part of the scope of work and not necessary.

10.9.11 Equipment Specifications

For safety and reliability, it is recommended that the external pumps (DS Schlumberger, BJ, etc.) be provided in all cases. For purposes of discussion in this report Halliburton pump specifications shall be used (not as a recommended vendor for these services, but because the author is more



familiar with this equipment than others). If a vendor other than Halliburton is chosen, their equipment will be comparable and little modification necessary except a review of pump-volume characteristics.

To follow the kill procedures, and in particular to maintain control of bottom hole pressure in all downhole conditions and in all-weather environments, a surface pumping spread per Figure I.10 will be necessary. Table I.3 shows the maximum recommended pumping spread where 10 each 612 HP pumps are provided. The lesser cases will require fewer pumps, but all the supporting booster pumps and holding tanks will remain the same.

Having a stimulation vessel provide the pumping requirements was considered; at first, it seemed to be a viable choice. However, upon review, certain factors ruled out the stimulation vessel as the primary pumping source. The major reasons were availability and possible conflicts with existing long term contracts with other area operators. The main reason is that these vessels are not equipped to handle a weighted fluid for extended periods of time. For safety reasons, the overall plan calls for kill weight fluid to be on standby ready to pump at a moment's notice. Thus the kill operation must be rigged up and kept on 24 hour notice during all of Phase III drilling. To use a stimulation vessel to provide pumping capacity, kill fluids must be transferred to the vessel on the fly making a complex hook up for both suction and discharge requirements. This cannot be considered 100% reliable in all weather and light conditions. Therefore installation of all pumping equipment on the main deck of the drilling rig is the most viable option.

Mixing

Mixing of the kill mud will be done by the drilling rig. The kill fluid should be transferred to 500 barrel top deck storage tanks sea fastened to the main deck of the drilling rig.

Suction Supply

Booster pumps will provide suction pressure for the high pressure pumping spread. These booster pumps shall feed into a 6" discharge ring that is fully manifolded to feed the high pressure pumps and return fluid to the pit area for conditioning if required. A tie in for a supply boat transfer of mud shall also be provided. A fluid transfer system shall also be supplied to move mud from the pit room to the main deck at 10 bpm rates. The booster system and/or the high pressure pumps shall be used to roll the fluid in the deck holding tanks, thereby assisting in maintenance of rheological properties. Densometers and flowmeters shall be installed at convenient locations in the suction supply system.

Discharge System

A 3" 10M working pressure distribution manifold will connect all high pressure pumps to a central manifold connected to the kill and choke line of the drilling rig. The central manifold shall have provisions for a tie to a stimulation boat, high volume return line to the holding tanks (for testing the system) and a relief-dump line overboard. Check valves will be required on the lines that connect the choke and kill lines. Tie in to the kill lines shall be in the moon pool area, bypassing the standpipe and choke manifold. Both high pressure and volume pumping will be required of this system.

Pumping Equipment

The pumping equipment shall be high pressure fracture treatment pumps. They shall be skid mounted in a protective frame acceptable to offshore operations. Due to limited deck space these frames must be so configured that it is permissible to stack the pump on top of one another. They shall be independently driven by diesel powered engines with normal controls, spark arrestors, and air shut offs. Discharge pressure shall be 10,000 psi working pressure. For pump unit calculation the capacity of a Halliburton HT-400 pump (4-1/2" liner with 8 inch stroke) powered by a GM Diesel 16V92 with 612 input horsepower is used. The pump pressure relationship, pressure volume

curve, has been used as supplied by Halliburton, Duncan, Oklahoma. This particular PVC is shown in Fig. I.9

Rather than applying a multitude of factors to each of the inputs to the pumping requirement. The author has chosen to use the maximum values and then apply an overall safety factor, therefore when predicting the number of pumping units required the calculated discharge pressure determines maximum unit discharge rather than applying factors of safety to each individual parameter.

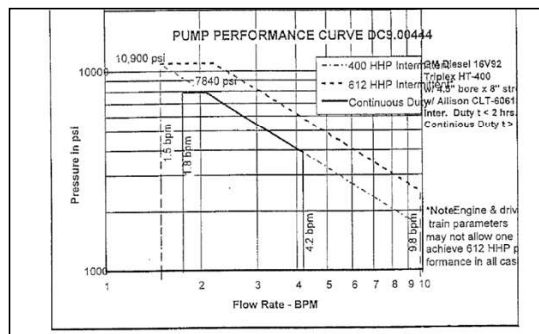


Figure I.9 Pressure Volume Curve

(Courtesy of Halliburton Energy Services, Duncan, OK)

The basis for calculating the required pumps follows:

$$N_p = Q_k / (1 - LO) \times SF / Q_m$$

Where :

N_p = number of pump units (round to integer)

Q_k = design kill rate, (bpm)

SF = safety factor (*)

LO = per cent leak off in decimal form, (*)

Q_m = max flow per unit, (bpm per unit) from manufacturer's data for 100% performance at anticipated discharge pressure, P_m

Example: For a given Scenario, the maximum discharge from the pressure loss model is 1600 psi (rounded to nearest 100 psi). From Figure C.9 the PVC discharge yields maximum available rate per unit, Q_m of 10.0 barrels per minute per unit if maximum horse power is expended. Assuming 10% leak off to the formation during the kill operation, LO becomes 0.10. The recommended overall safety factor, SF , is 1.50. Thus for this scenario the required number of pumps will be:

$$N_p = 47.52 \times 1.5 / (1 - 0.1) \times 10 = 7.92 \text{ or } 8 \text{ rounded up.}$$

Table I.3 presents the design conditions for pumping units if Halliburton HT-400 16V92 powered units with 4-1/2" liners (162 max hp each unit) are chosen as the primary pump unit.

Control System

Control of all high pressure pumps shall be by remote control from a single unit so that one person can control all the pumps in the spread. Constant communication with the command center

(computer skid) shall be necessary. Pump and bottom hole pressure as well as volume pumped shall be electronically recorded. Digital displays of discharge pressure, cumulative pumping rate, density of discharge fluid and cumulative volume shall be displayed. The control and recording devices shall be housed in a single module that has space for the pumping vendor technicians as well as 4 company's representatives.

Safety System

Safety systems shall be provided so that the technicians can monitor:

- critical engine functions on pumps and boosters
- fluid levels in holding tanks
- communications from rig command center
- Bottom hole pressure and temperature from a surface read out wireline conveyed pressure gauges located in the relief well.

A relief valve in the overboard line shall be installed. This shall have automatic reset. Check valves shall be installed in the discharge line and at critical points in the discharge piping system.

Testing / Training

Testing of the pumping system should be done with sea water and with weighted fluid. The discharge system has a return and overboard line for this purpose. The pumping of 2000 barrels should take less than one hour at design rates; however the final stages of the kill may have very low rates. Therefore the pumps should be tested to see that they can deliver the design rate and horsepower (with safety factor) by pumping against a choke with sea water for 30 minutes at 3300 psi. Intermittent (10 minutes) pump test at 7,000 psi with all pumps on line will test that all available horsepower can be delivered through a range of working pressures. This will ensure flexibility of the operation should it become necessary to alter the job specifications.

A weighted fluid pumping test should be performed to insure that the suction and discharge systems provided are adequate at the design rates. The actual frictional losses in the system from the discharge, deck lines, manifold and kill line to the BOP should be determined by circulation. This test should be done with weighted fluid and with sea water while waiting on cement after setting 9-5/8" casing or earlier if possible.

An important aspect of the kill procedure will be the coordination of all service company personnel and company representative. It will be critical that information flow freely to the onsite management team. The trial runs to test the pumping system should include a full test of all monitoring systems and personnel involved.

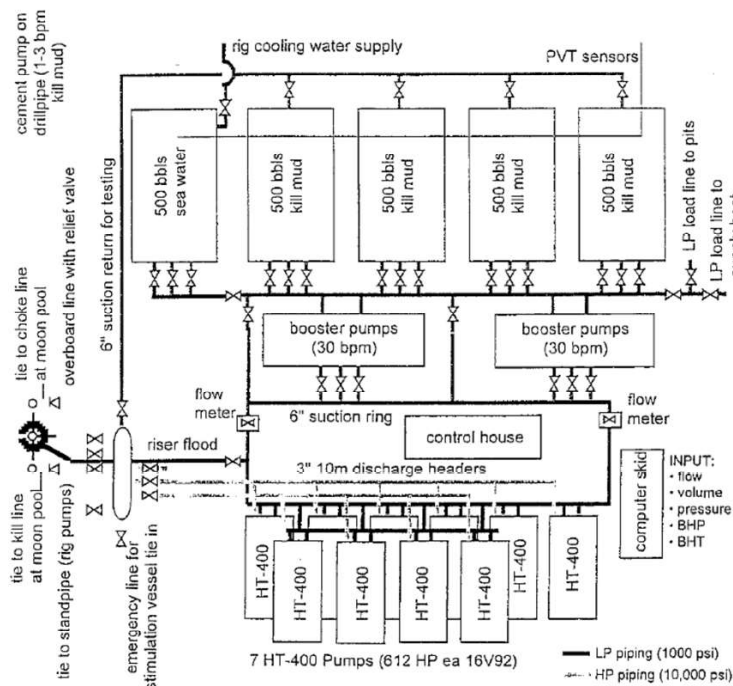


Figure I-10

10.10 SURFACE CONTROL SPECIAL SERVICES

10.10.1 Hot Tapping and Valve Drilling

Hot tapping and valve drilling equipment has been used on blowouts to allow pumping into wellheads, tubulars or fire frozen valves. This equipment is available from most major blowout specialist companies as part of their service capabilities.

In a hot tap, a saddle clamp is installed around the tubular and a pack off is energized. Within the lubricator a drill bit cuts through the tubular with pressure held slightly higher on the outside than on the inside so positive indication that a hole has been made is seen. After the hole is cut, it can be reamed out up to 1". Valve drilling machines are available to drill out frozen gates. Up to 3" holes have been drilled with larger hole sizes milled out.

These services are available from Boots & Coots, Cudd, Halliburton, HWC and others. Pipeline companies use hot tap equipment and may be adaptable to certain applications. Saddle clamp sizes should be investigated. A specialist should be utilized in any case for safety.

10.10.2 Freezing

Freezing is used to place an ice plug within shut in wells (within pipe, wellheads or annulus) to allow removal, repairs or replacement of wellhead equipment. Freezing has not been used to control a high volume blowing well.

Some inventors attempted to market devices using liquid nitrogen to freeze off blowing wells in Kuwait, but simpler control methods were available. Difficulties were seen in maintaining the freeze plug of frozen oil and brine while making extensive surface repairs to blown up wellhead equipment.

Freezing techniques usually use dry ice to freeze water or fresh water-bentonite slurries. Methanol can be used with dry ice to get a lower temperature. A 75% methanol/water mixture has a freeze temperature of <-200° F. Methanol water mixtures could be potentially cooled by liquid nitrogen and the cold methanol/water mixture circulated around the area to be frozen.

This would allow control of the applied temperature to the steel. Problems with low fracture toughness in super cooled steels have been observed in nitrogen pumping service when pump rates exceeded heater capabilities and liquid nitrogen was pumped into wells.

Freezing services are available from Boots & Coots, Cudd, Halliburton, HWC and others.

10.10.3 Pneumatic Casing Cutters

Pneumatic cold cutters are used to strip away outer casing strings to expose inner casing strings for well capping. ABB Vetco Gray has equipment available to make vertical stripping cuts to split casing strings. The pneumatic cold cutters are commonly used in the pipeline business. Common sources are ABB Vetco Gray, Boots & Coots, Enterra Wellcat, Porta-lathe and others.

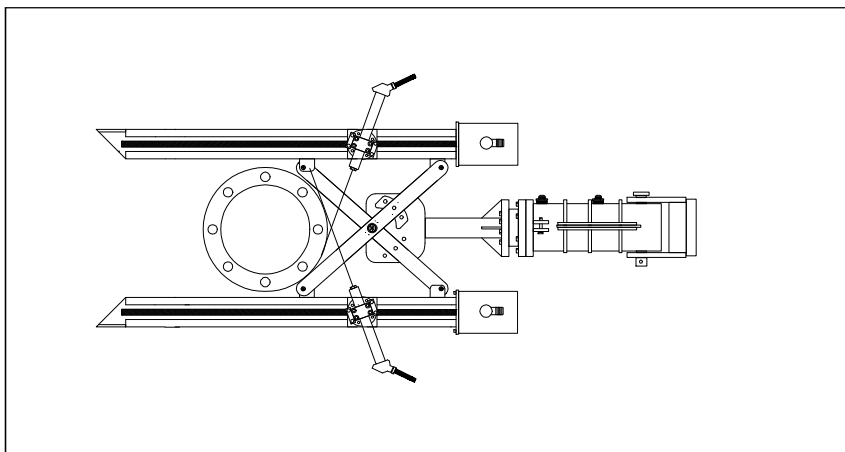
10.10.4 Abrasive Jet Cutters

The Halliburton abrasive jet cutter was developed to deal with the aftermath of the Arabian Gulf War. Because of the extensive number of wells that were burning, Halliburton developed a way to rig up quickly, cut from a remote location and rig down quickly to move to another well. This cutter was designed to cut the casing below the braden head, which cuts all the casing strings, cement between casing strings and tubing in the center.

The abrasive jet cutter incorporates two jet nozzles opposing each other. A hydraulic motor turns a linear screw that moves the nozzles either in a forward or reverse direction. The cutter is positioned on each side of the wellhead and pressure from the pumping equipment is established

at 10,000 psi at approximately 4 bbls/min. Sand is added to the blender and the sand slurry is delivered to each nozzle. The nozzles are then tracked forward cutting everything between the two nozzles.

All hydraulic lines are encased in a water jacket due to the intense radiant heat associated with a blowout. Also as an added feature the cutter can be rotated clockwise to counter-clockwise and raised up or down. This simplifies trying to cut on a leaning or damaged wellhead.



This is controlled by a small hydraulic power pack that is incorporated into the skid that houses the cutter during shipping. This power pack and control system can be placed up to 250 feet from the actual cutter assembly. From this safe distance the well control specialist can control the movement of the cutting jets.

The abrasive jet cutter has cut a forty eight inch diameter flange the largest to date. The average cut usually made with the cutter is between twenty four inches to eighteen inches in diameter. With a cutting pressure of 10,000 psi, a pump rate of four barrels per minute and a pound per gallon sand concentration the cutting time is less than one hour for these applications.

10.10.5 Requirements for the Halliburton Abrasive Jet Cutter

- Two thousand hydraulic horsepower (2,000 hhp) – that has been horsepower tested for at least twenty minutes at 10,000 psi and 4 bbls/min. If 2,000 hhp is not available, contact Halliburton Well Control in Duncan.
- Pumping iron – This depends on each individual blowout location. Usually five hundred feet of straight two inch 1502 with an assortment of style 50 angle wing chiksans and tees to wye the pumping equipment together. Suction hoses to hook up pumps.
- Sand Requirements – 20/40 Ottawa frac sand is preferred but 20/40 Brady, 20/40 inter-prop or 20/40 bauxite can be used if the Ottawa is not available. Amount per hour of cutting = 12,500 pounds.

Halliburton Well Control will supply the blender and in most cases a centrifugal pump to mix the sand and water together.

10.10.6 Explosive Jet Cutter

Shaped charges can be made in the field using raw C4 plastic explosive in fabricated holders. Point cuts, linear cuts and circular cuts can be fabricated by firefighting explosive experts. Manufactured cutting charges are stocked by explosive manufacturers in some regions, but cannot be custom configured to the application. These are generally the same companies that make oil well perforating charges (GOEX and JRC).

10.10.7 Hydraulic Simulator

Hydraulic modelling software and specialists will be required to help perform blowout scenario diagnostics and kill simulations.

Planning the kill strategy for a 1989 underground blowout in the North Sea required development of an improved flow simulator. The hydraulic kill simulator was based on the industry standard, two phase pipe flow model, OLGA. After the project, the planning team realized that they gained considerable advantage from using a transient two phase flow simulator for comparing various kill scenarios. Since then, the OLGA-WELL-KILL simulator has been used successfully for a number of intervention design plans.

The ability to analyse hydraulic kill scenarios quickly and find their effect on the rest of the intervention operation is critical to project success. A specialized need was therefore identified for a multiphase, time transient, flow simulator designed for easy blowout kill analysis. This need was the driver that motivated the continued modification of the pipeline code for well flow and kill simulations.

During a blowout kill, up to six fluids can be present simultaneously in the well reservoir; oil, gas and water; kill water, intermediate and final kill mud. Conventional kill models cannot easily evaluate multiphase flow where heavy kill muds are used.

Simulations handle this by first simulating the dynamics of a liquid/gas biphasic flow regime, then comparing this to a simulation using averaged properties in a light weight liquid phase. The kill phase is then introduced and a dynamic two phase simulation is performed until a steady state condition is reached. Afterwards, the next phase can be introduced and the simulations can be restarted at any time.

Modelling is accomplished using a number of controllers set to contain the simulation within the physical constraint of the real blowout. The controllers can, for example, be set on the following parameters:

- Pump rate.
- Pump horsepower.
- Formation collapse pressure.
- Casing burst pressure.
- Surface injection pressure.
- Bottom hole pressure (min/max).
- The simulation modeling includes
 - Pump performance
 - Non-Newtonian fluid flow (for mud)
 - Fluid temperature and pressure response
 - Inflow modelling (multiple if needed)
 - Leaks (multiple if needed)
 - Back pressure (outflow conditions)

- Several reservoir inflow models
- Variable reservoir pressure
- Path chokes (critical and sub critical)

In practical use, the modelling is usually taken through a number of steps starting with a PVT fluid characterization of the reservoir fluids. The blowout is then modelled to match all available data.

The next step is to set up a constant rate kill simulation to work out the range for the simulation of the actual dynamic kill. This is also useful in evaluating allowance for losses between wells (for relief well kills) as well as for the kill fluid density, and for velocity and pressures at critical points in the blowout path. The fully dynamic simulations can then incorporate all the actual constraints in the kill such as casing pressure ratings, fracture pressures, inflow performance and reservoir pressure (dynamically versus time, if necessary), pumping plant and mud properties.

The simulation yields an actual pump schedule vs. time (with rates and pressures at any chosen point in the flow path). If needed, a number of sensitivities can be developed to evaluate kill effectiveness during the actual pumping. This later step can often prove useful when there are unknowns in the kill (such as communication between relief well and blowout well, actual blowout flow path or reservoir performance.)

Applications include the following:

- Kill with different mud densities in the well.
- Partial losses during kill.
- Multiple blowout paths, cross flows and leaks.
- Multiple relief wells pumping at different rates.
- Underground blowouts from a drilling rig.
- Simultaneous bullheading and dynamic kill.
- Off bottom or momentum kills, shallow gas blowouts.
- Horizontal well flow analysis.
- Slugging in long reach production wells.
- Rates required to circulate out a kick in horizontal wells.
- Alternating gas and water injection.
- Sensitivity analysis by varying parameters.

10.11 EMERGENCY CONTACT LISTS

Refer to current contact lists provided by the various department managers.

Use this link to find everyone in the oil field

<https://www.oildex.com/resources/directory/>