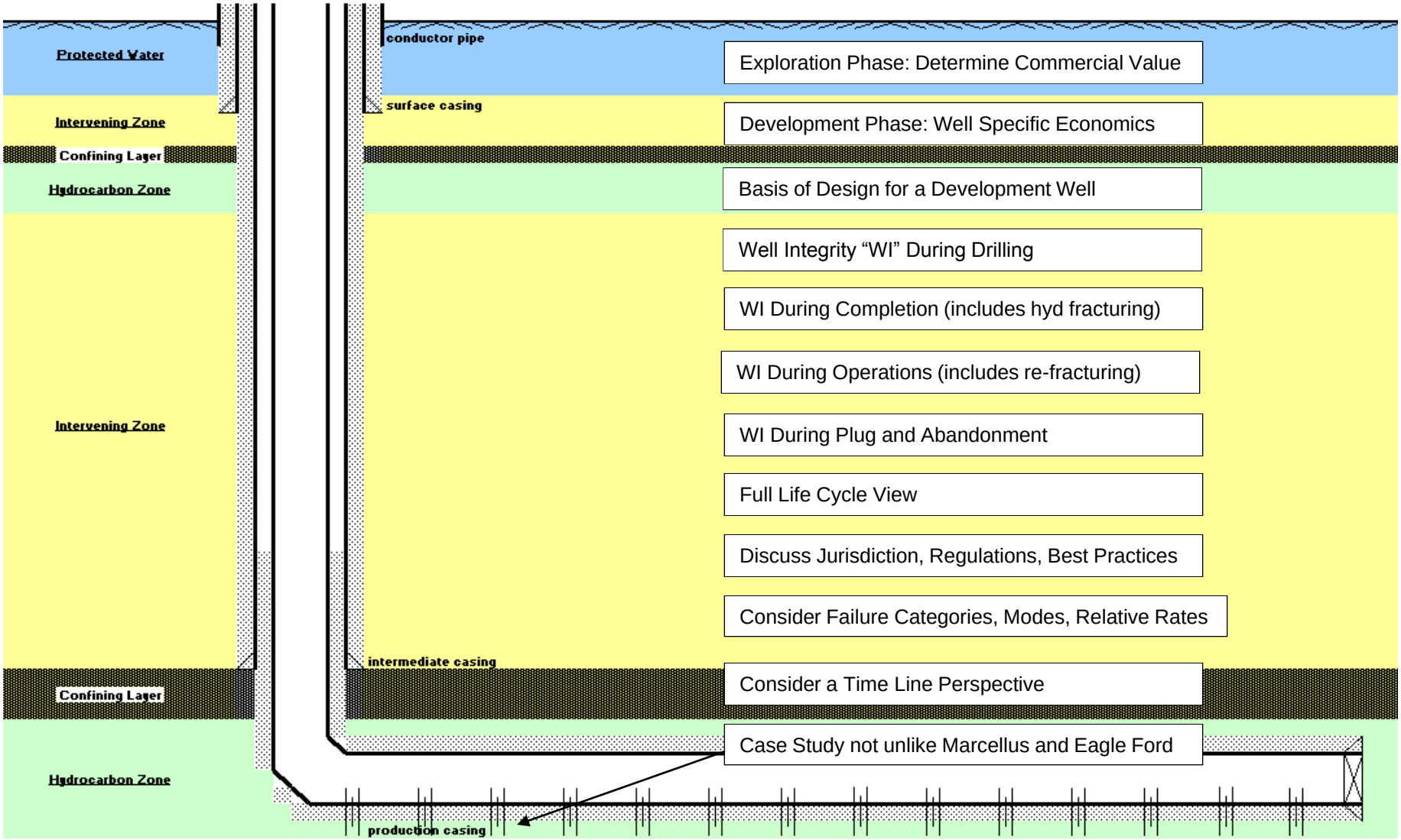
EPA Hydraulic Fracturing Study Technical Workshop #2 March 10-11, 2011

Well Integrity Case Study by Lloyd H. Hetrick

Slide 1 of 22 – Well Integrity Narrowly Defined as the Prevention of Fluids Migration into Protected Water



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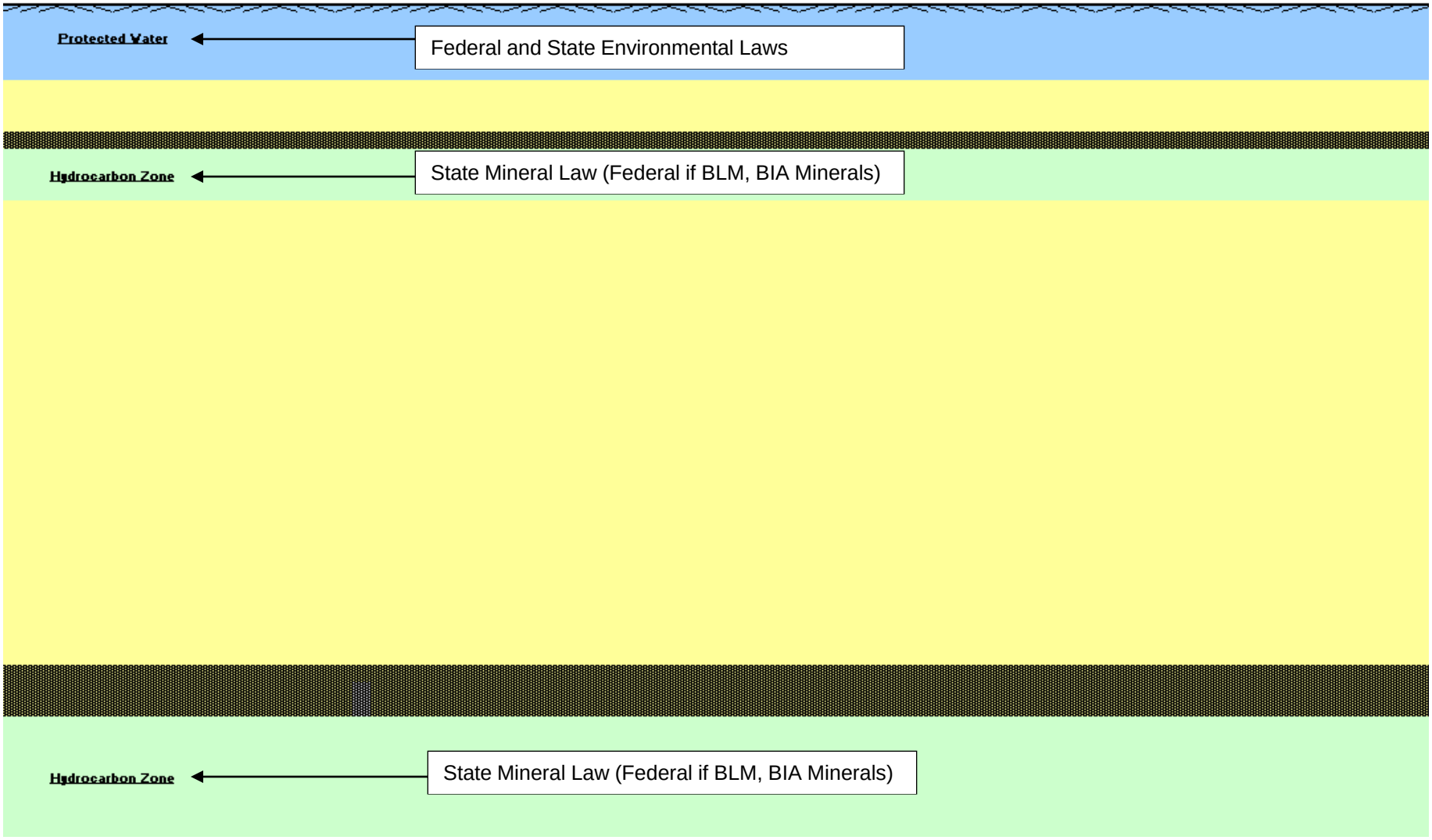
Slide 2 of 22 – Jurisdiction



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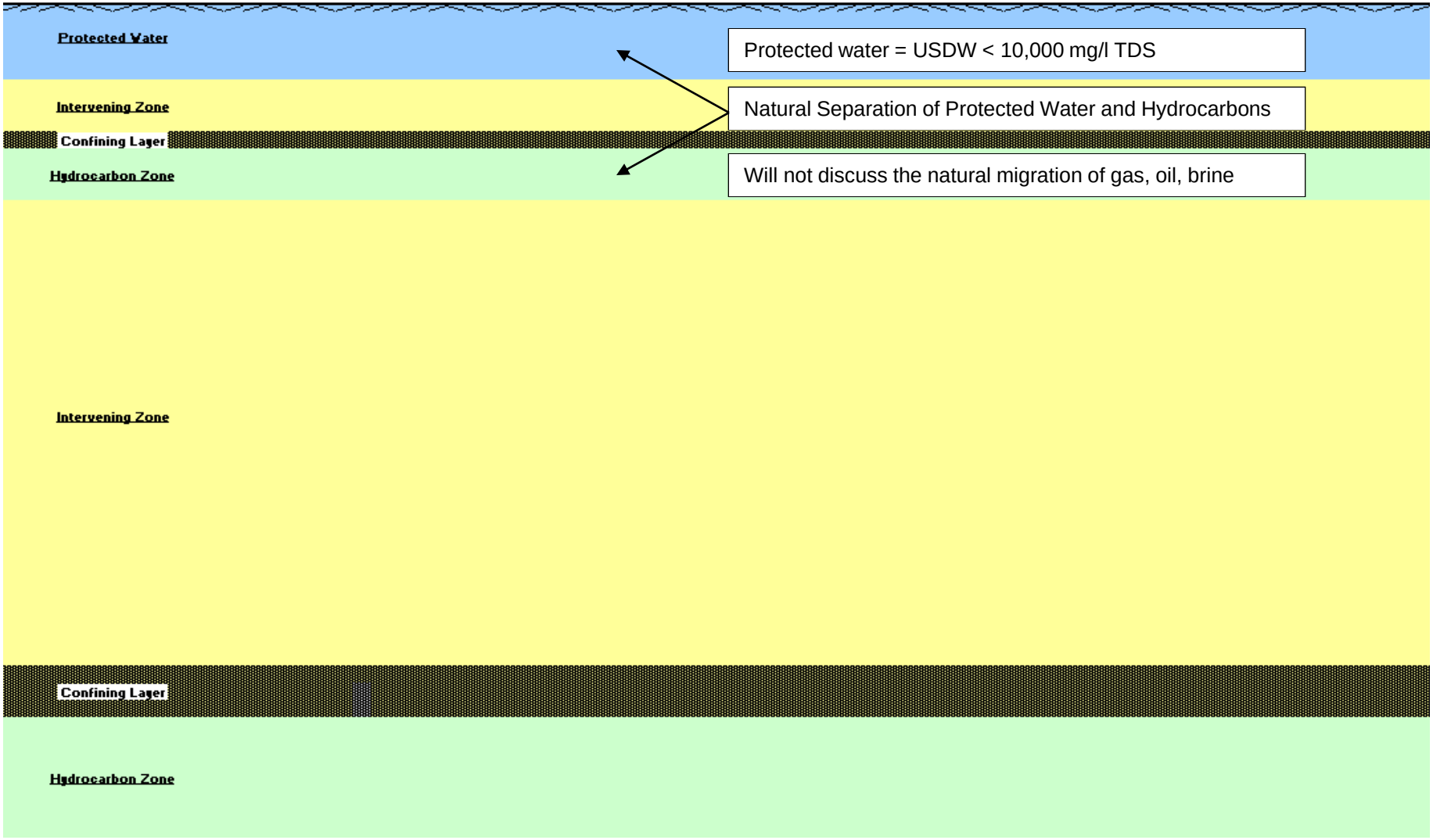
Slide 3 of 22 – Natural Separation of Protected Water and Hydrocarbons, in most cases



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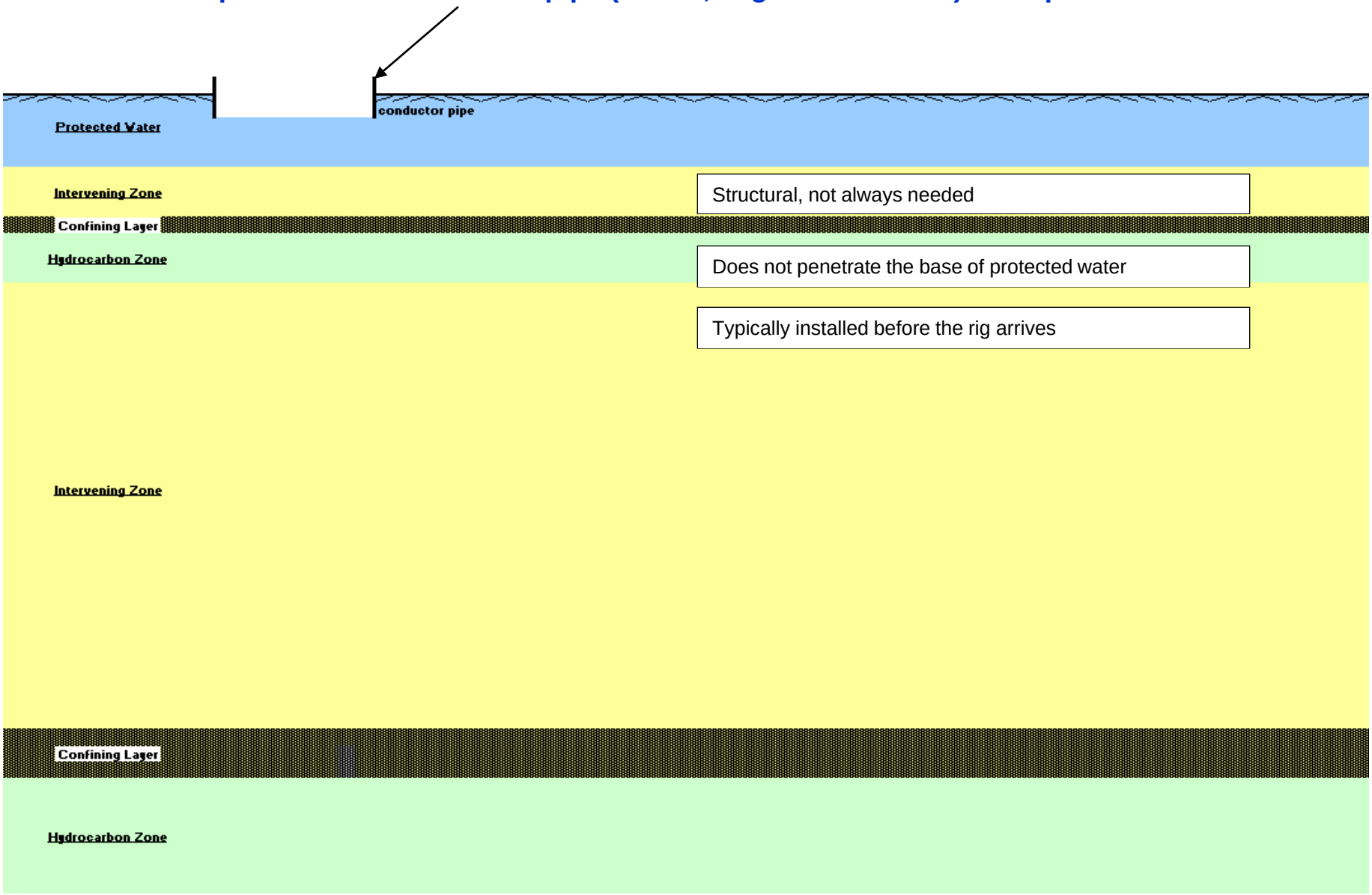
Slide 4 of 22 – Spud well with conductor pipe (driven, augered or drilled) no impact on Protected Water



Structural, not always needed

Does not penetrate the base of protected water

Typically installed before the rig arrives

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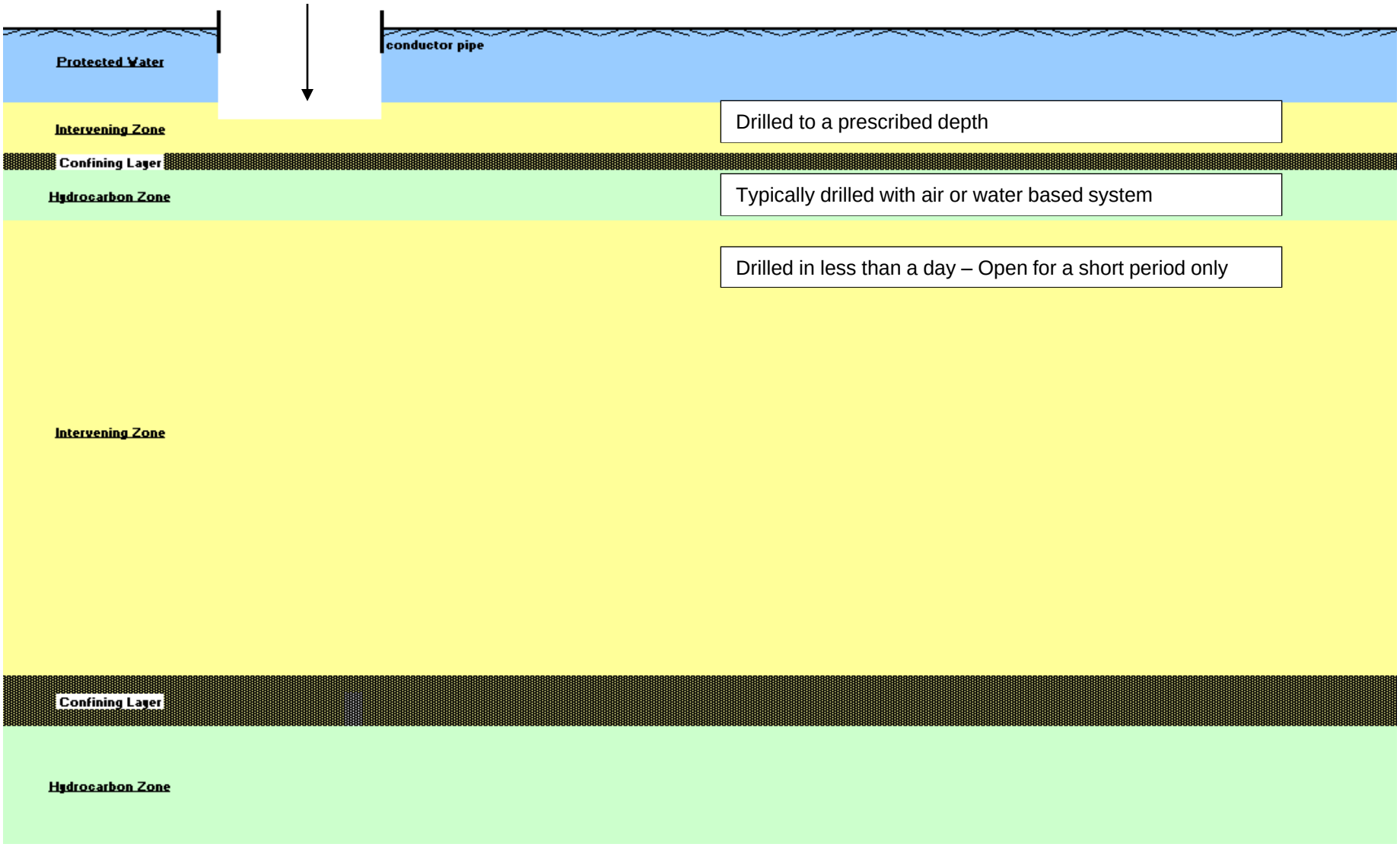
Slide 5 of 22 – Well is drilled to a prescribed depth below Protected Water



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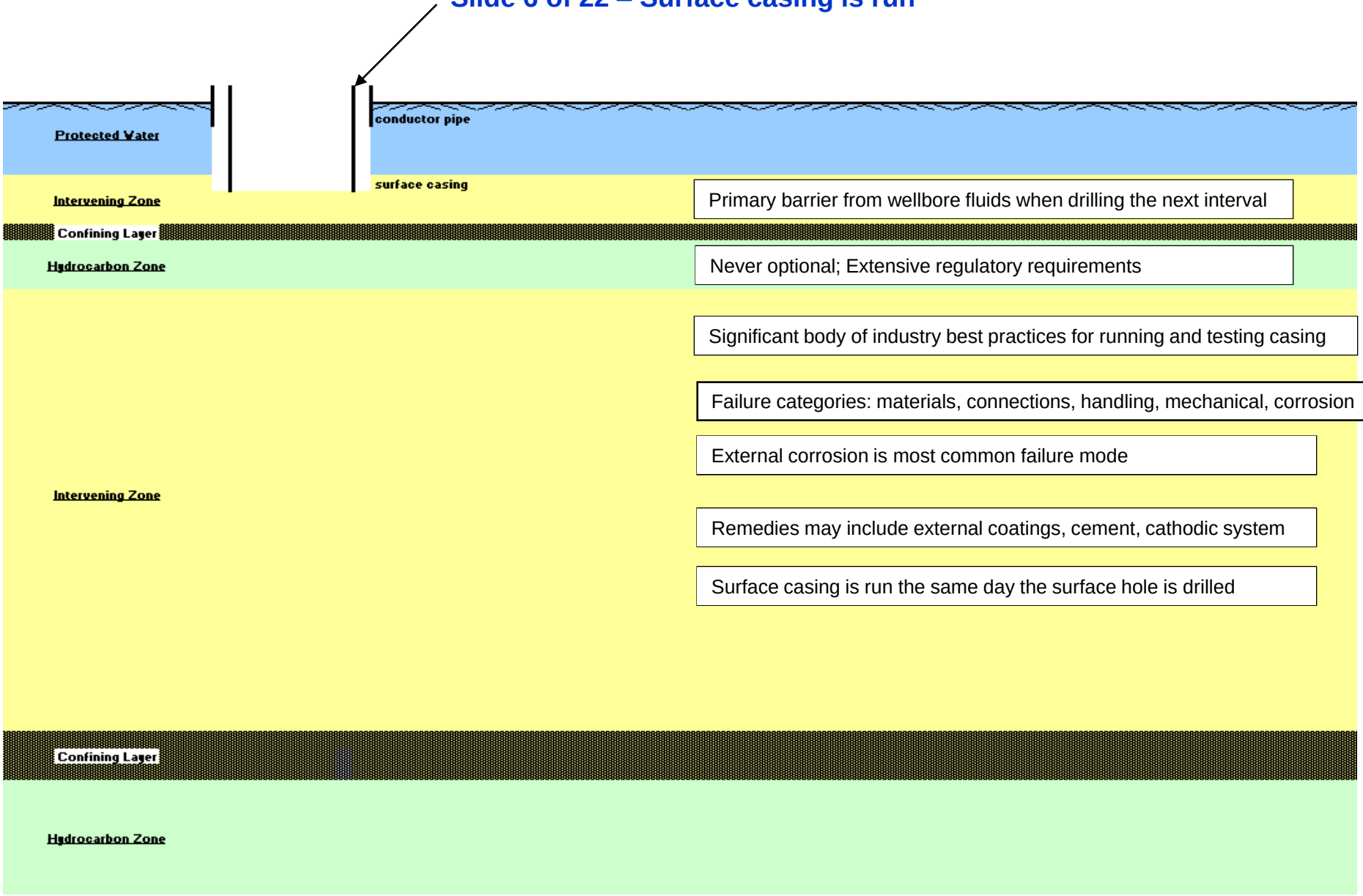
Slide 6 of 22 – Surface casing is run



- Primary barrier from wellbore fluids when drilling the next interval
- Never optional; Extensive regulatory requirements
- Significant body of industry best practices for running and testing casing
- Failure categories: materials, connections, handling, mechanical, corrosion
- External corrosion is most common failure mode
- Remedies may include external coatings, cement, cathodic system
- Surface casing is run the same day the surface hole is drilled

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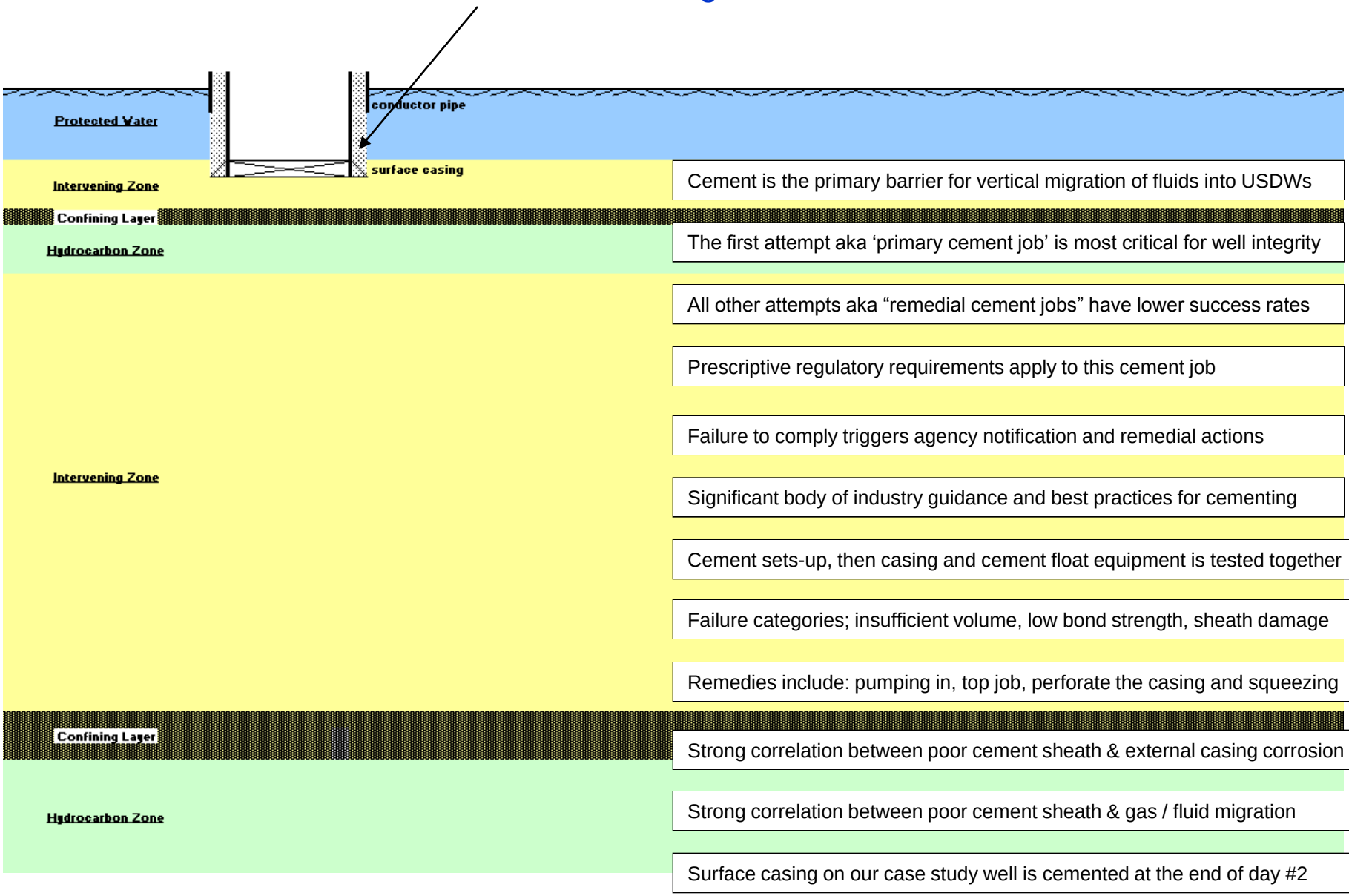
Slide 7 of 22 – Surface casing is cemented and tested



- Cement is the primary barrier for vertical migration of fluids into USDWs
- The first attempt aka ‘primary cement job’ is most critical for well integrity
- All other attempts aka “remedial cement jobs” have lower success rates
- Prescriptive regulatory requirements apply to this cement job
- Failure to comply triggers agency notification and remedial actions
- Significant body of industry guidance and best practices for cementing
- Cement sets-up, then casing and cement float equipment is tested together
- Failure categories; insufficient volume, low bond strength, sheath damage
- Remedies include: pumping in, top job, perforate the casing and squeezing
- Strong correlation between poor cement sheath & external casing corrosion
- Strong correlation between poor cement sheath & gas / fluid migration
- Surface casing on our case study well is cemented at the end of day #2

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Slide 8 of 22 – Surface casing shoe and formation are integrity is tested

The FIT tests the casing shoe and adjacent formation together

Not a leak-off test, it does not establish a limit

Assessment of well's ability to withstand pressure to the next casing point

For our case study well we are now at the end of day #3

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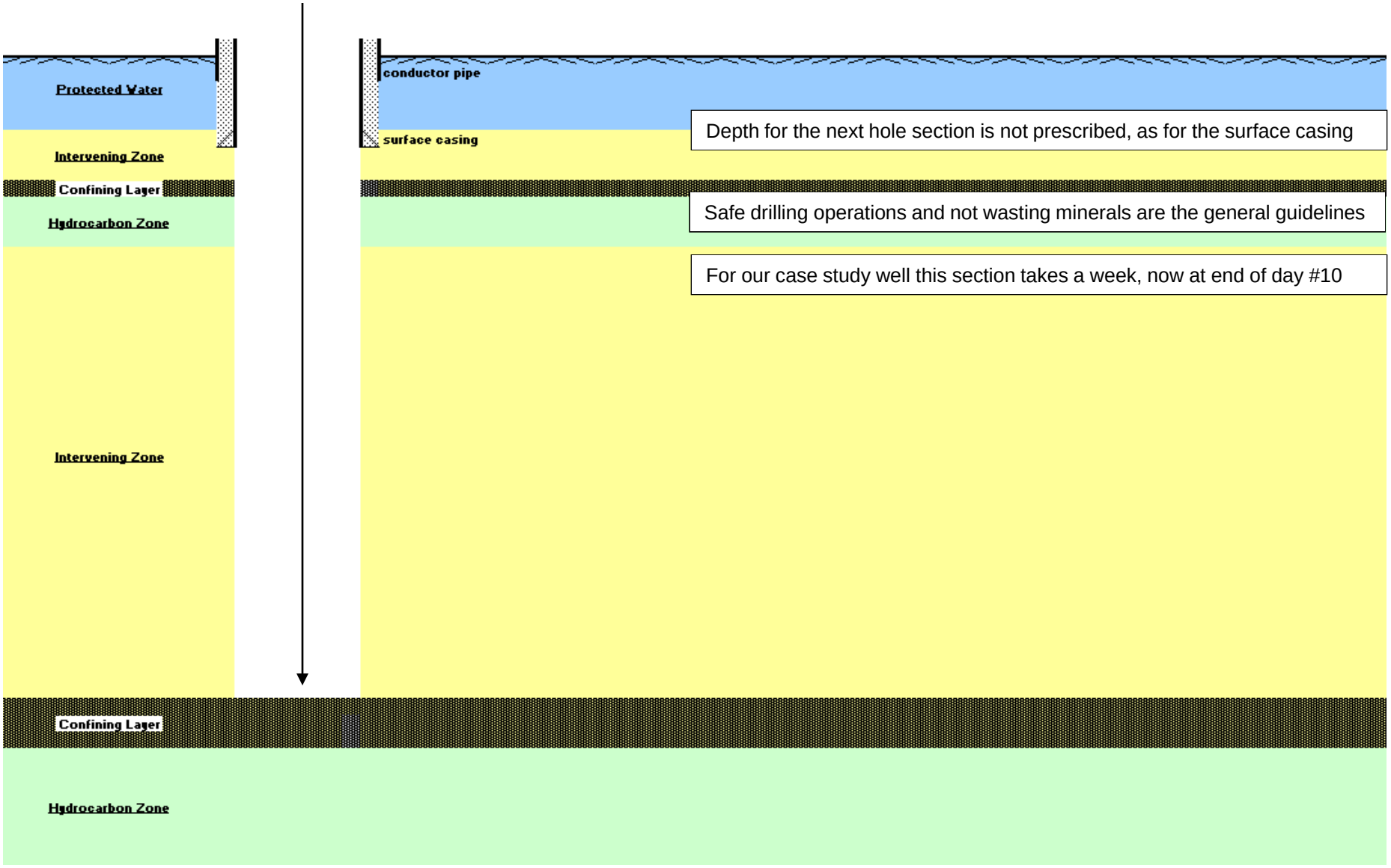
Slide 9 of 22 – Next section of hole is drilled



Depth for the next hole section is not prescribed, as for the surface casing

Safe drilling operations and not wasting minerals are the general guidelines

For our case study well this section takes a week, now at end of day #10

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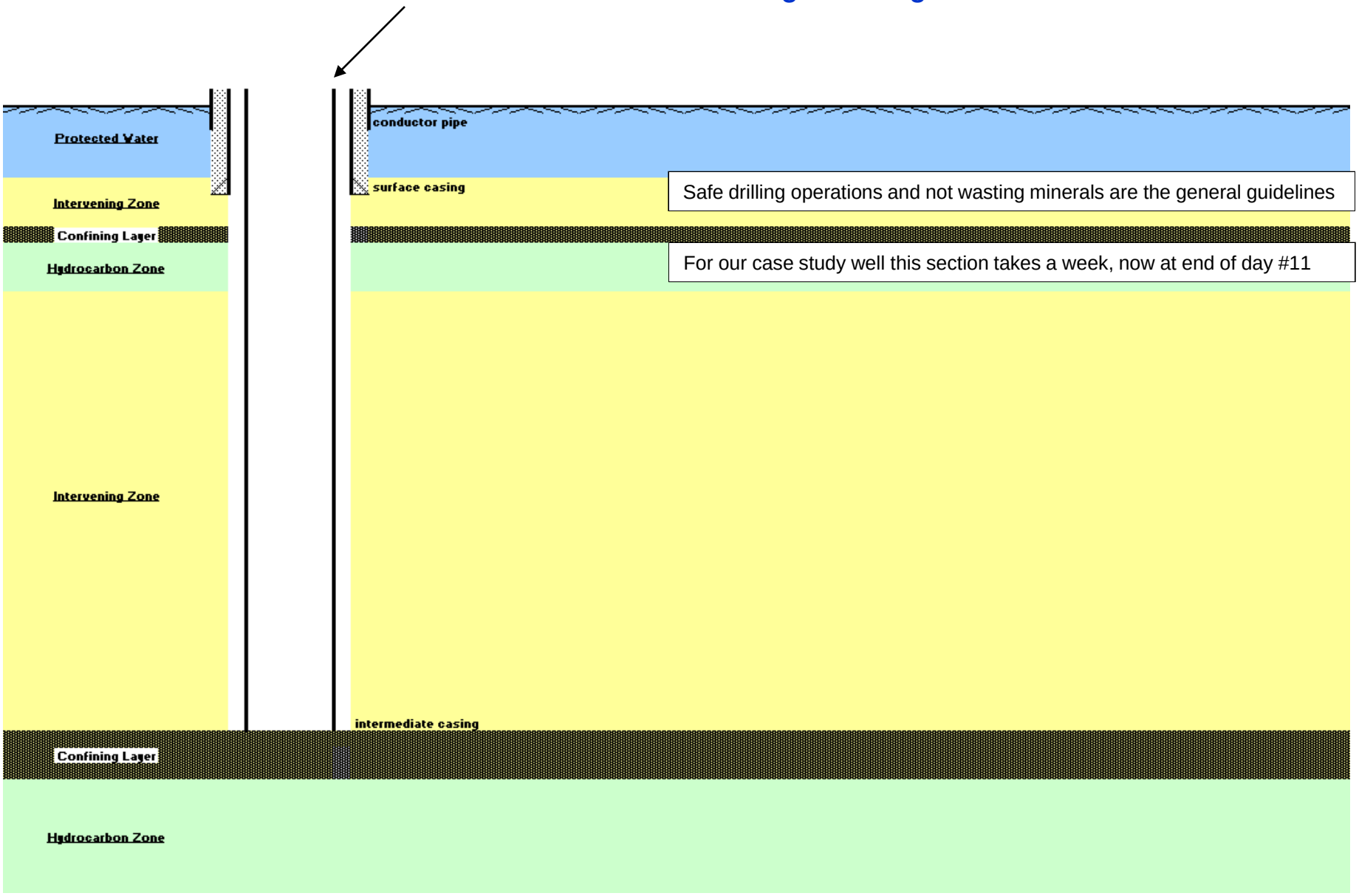
Slide 10 of 22 – Intermediate string of casing is run



Safe drilling operations and not wasting minerals are the general guidelines

For our case study well this section takes a week, now at end of day #11

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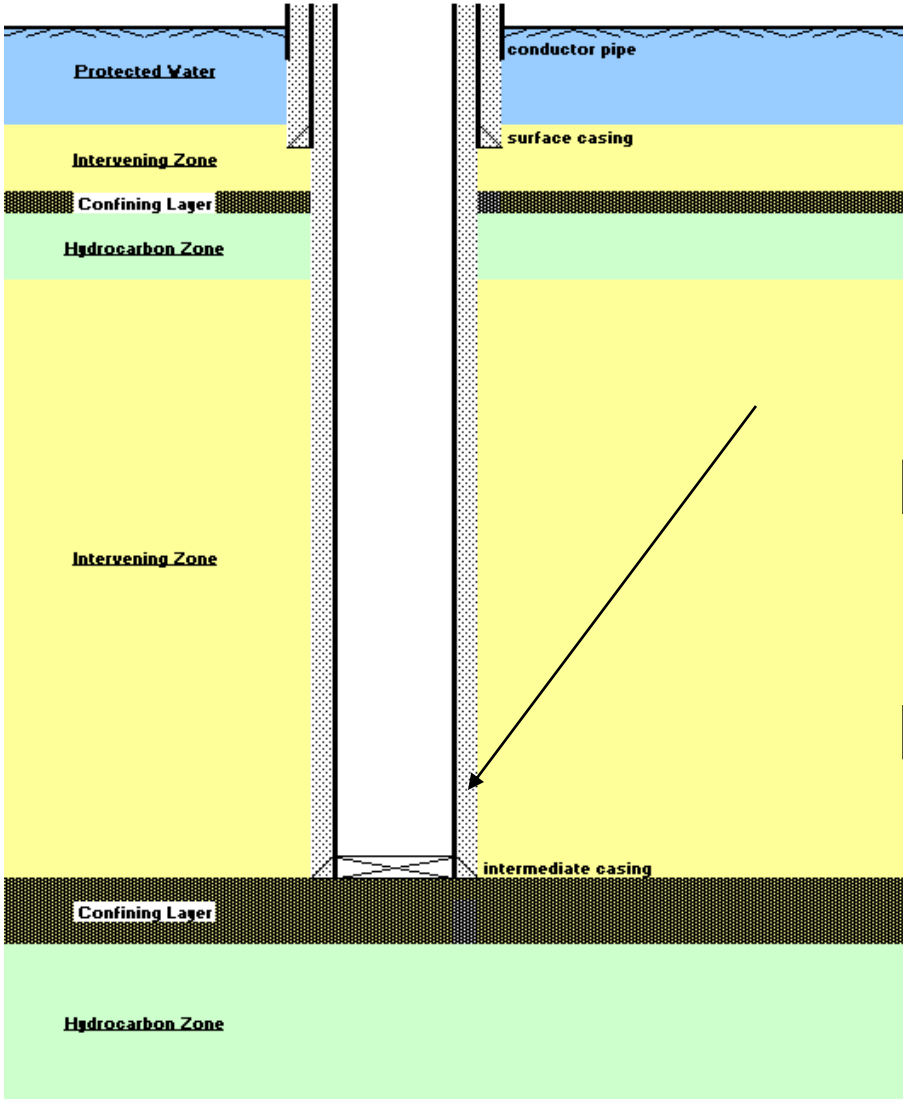
Slide 11 of 22 – Intermediate casing is cemented and tested



- Cement is the primary barrier for vertical migration of fluids
- The first attempt aka ‘primary cement job’ is most critical for well integrity
- All other attempts aka “remedial cement jobs” have lower success rates
- Less prescriptive regulations than for the surface casing cement job
- Cement sets-up, then casing and cement float equipment is tested together
- Failure categories; insufficient volume, low bond strength, sheath damage
- Remedy is to perforate the casing and squeeze
- Strong correlation between poor cement sheath and external casing corrosion
- Strong correlation between poor cement sheath and gas / fluid migration
- Intermediate casing on case study well is cemented by the end of day #12

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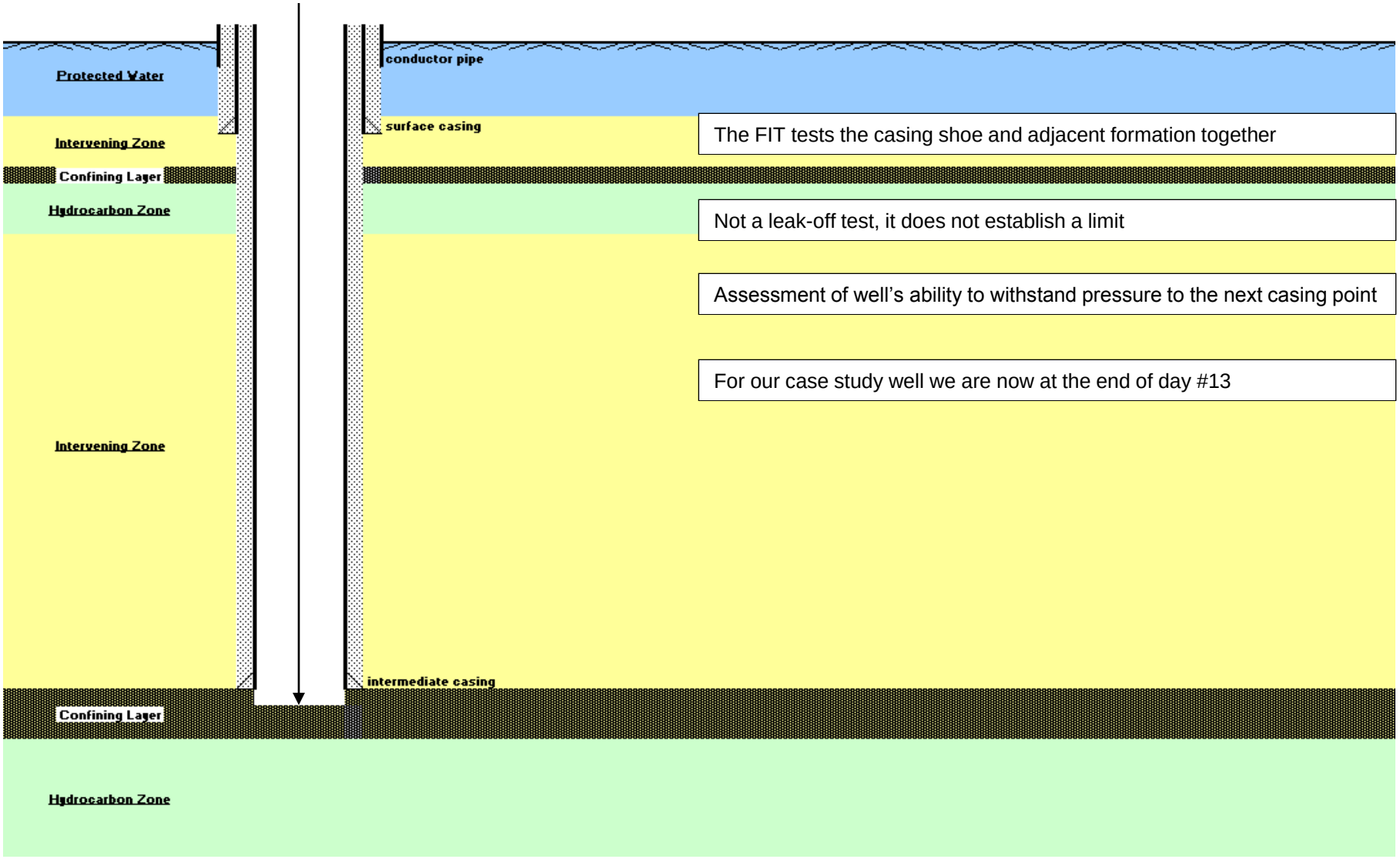
Slide 12 of 22 – Intermediate casing shoe and formation integrity are tested



The FIT tests the casing shoe and adjacent formation together

Not a leak-off test, it does not establish a limit

Assessment of well's ability to withstand pressure to the next casing point

For our case study well we are now at the end of day #13

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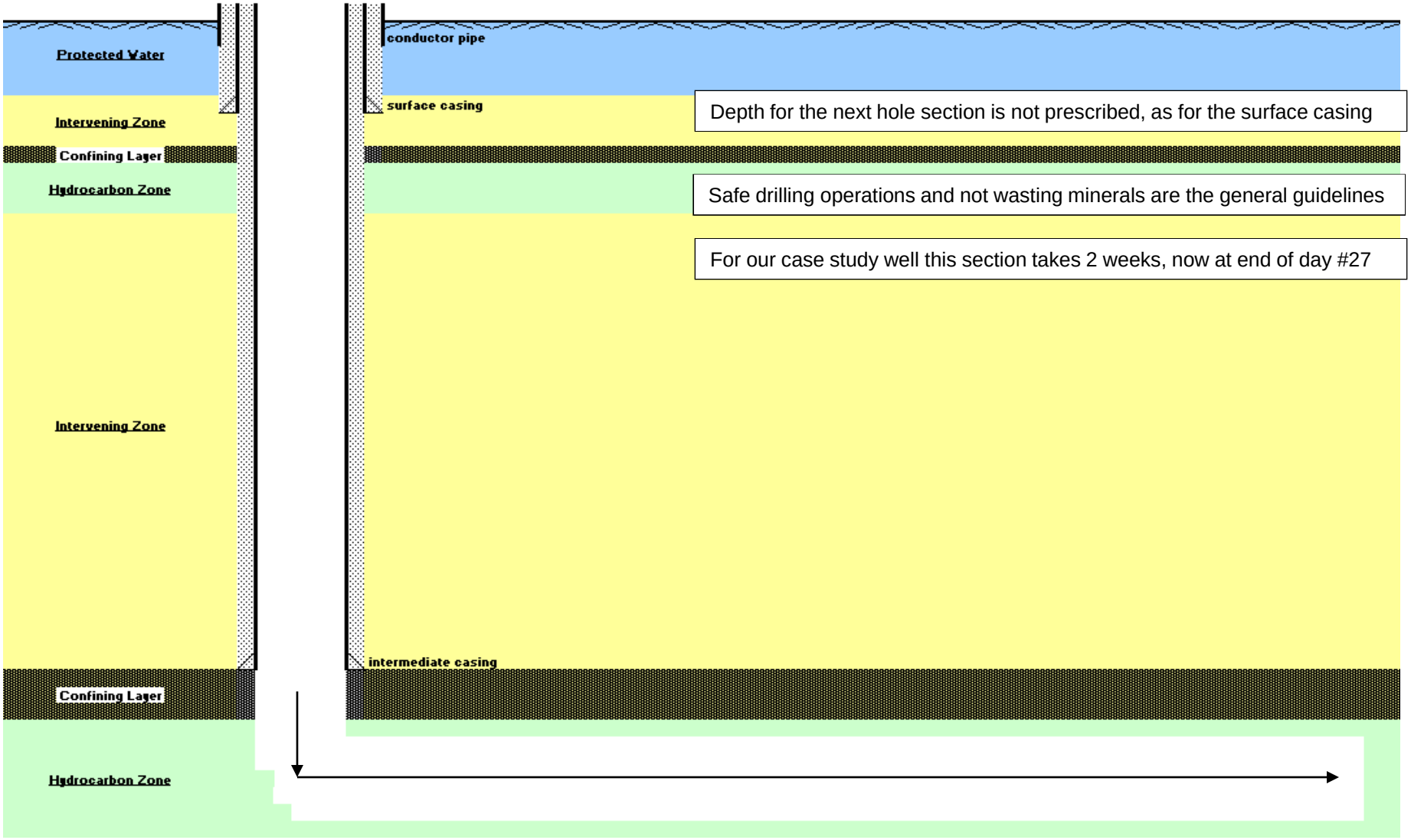
Slide 13 of 22 – Next section of hole is drilled



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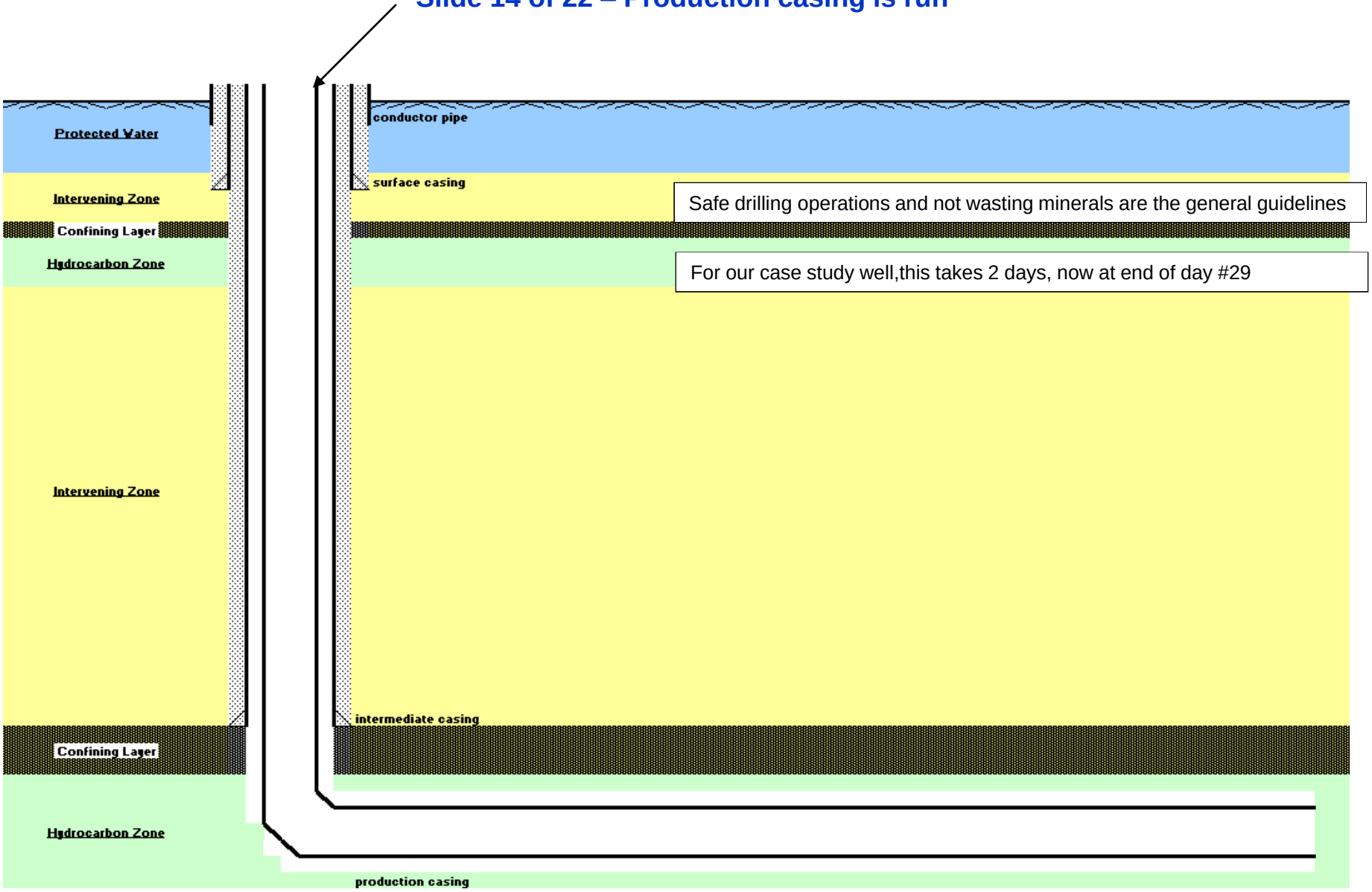
Slide 14 of 22 – Production casing is run



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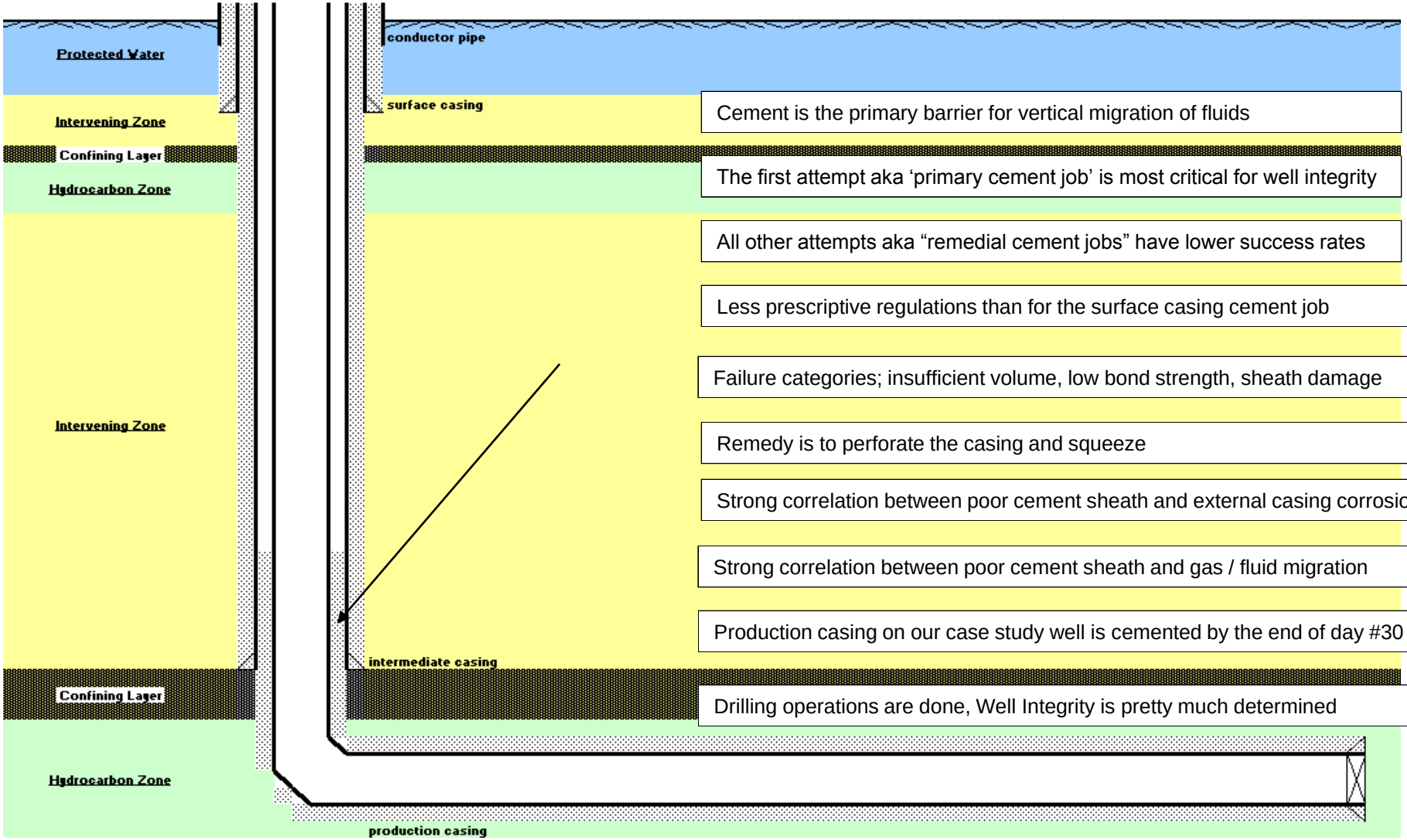
Slide 15 of 22 – Production casing is cemented, Drilling phase is done



- Cement is the primary barrier for vertical migration of fluids
- The first attempt aka ‘primary cement job’ is most critical for well integrity
- All other attempts aka “remedial cement jobs” have lower success rates
- Less prescriptive regulations than for the surface casing cement job
- Failure categories; insufficient volume, low bond strength, sheath damage
- Remedy is to perforate the casing and squeeze
- Strong correlation between poor cement sheath and external casing corrosion
- Strong correlation between poor cement sheath and gas / fluid migration
- Production casing on our case study well is cemented by the end of day #30
- Drilling operations are done, Well Integrity is pretty much determined

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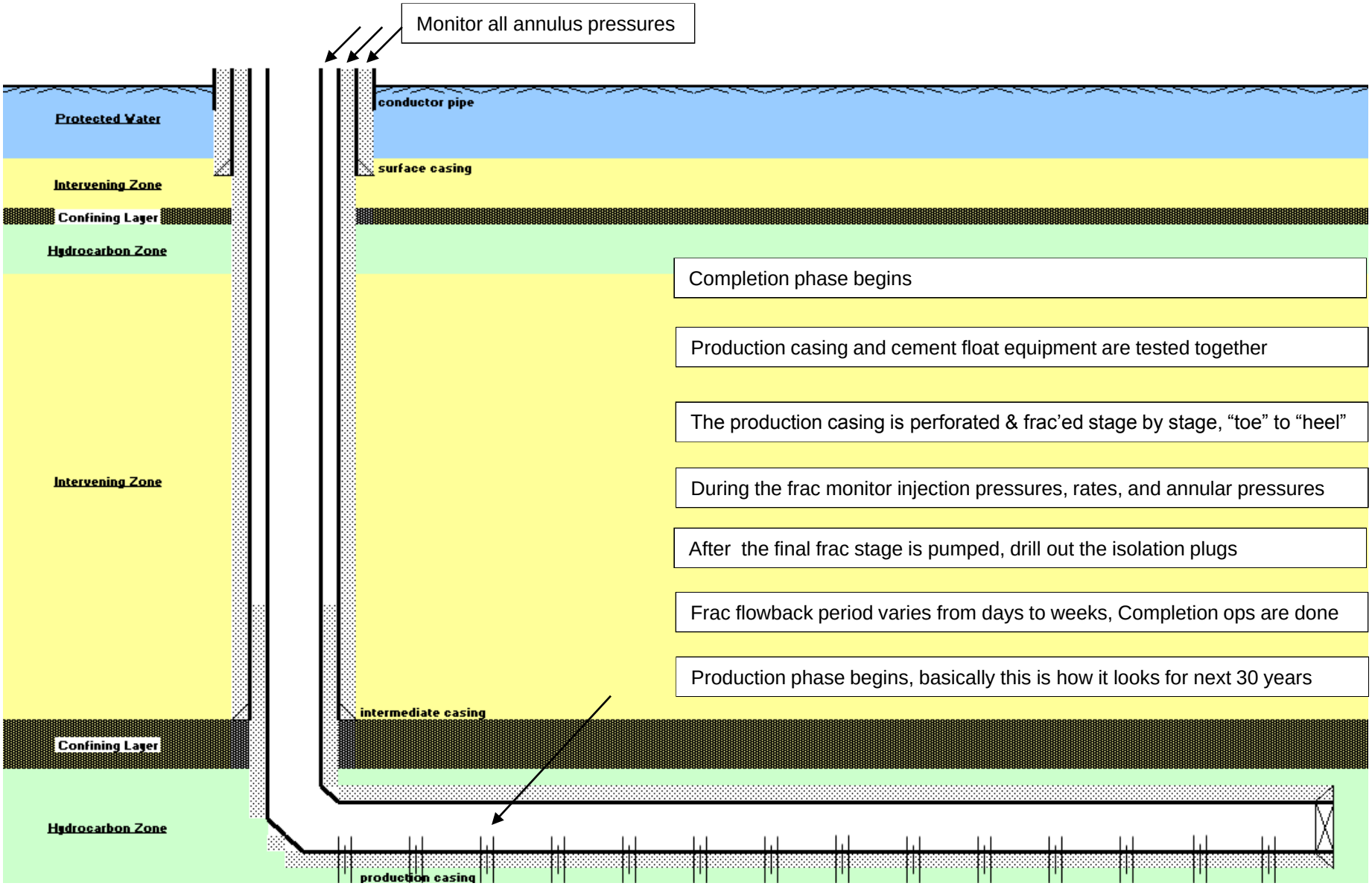
Slide 16 of 22 – Completion phase: perforate, hydraulically frac, flowback, production begins



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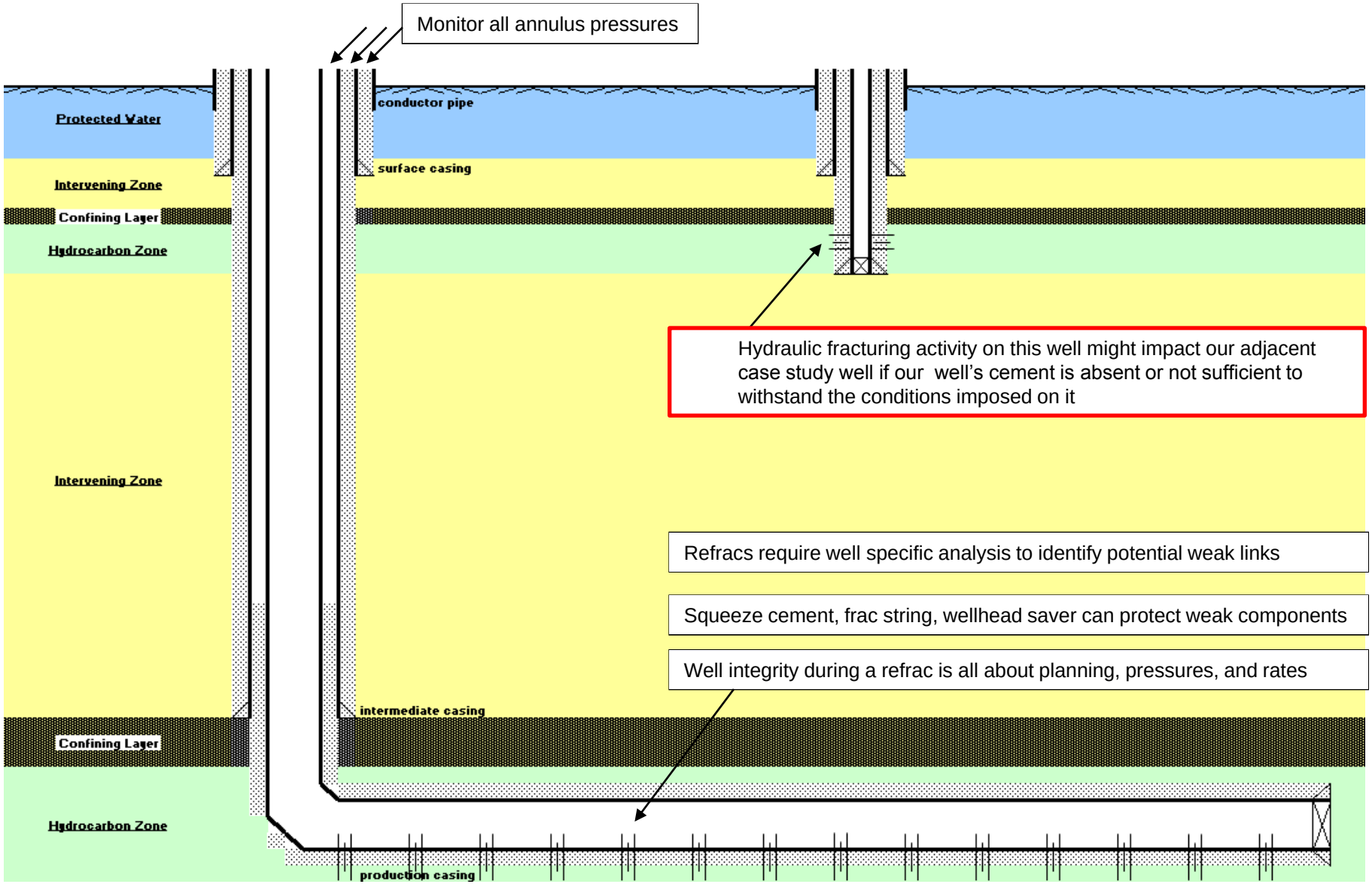
Slide 17 of 22 – Refrac and Adjacent Well Frac Scenarios



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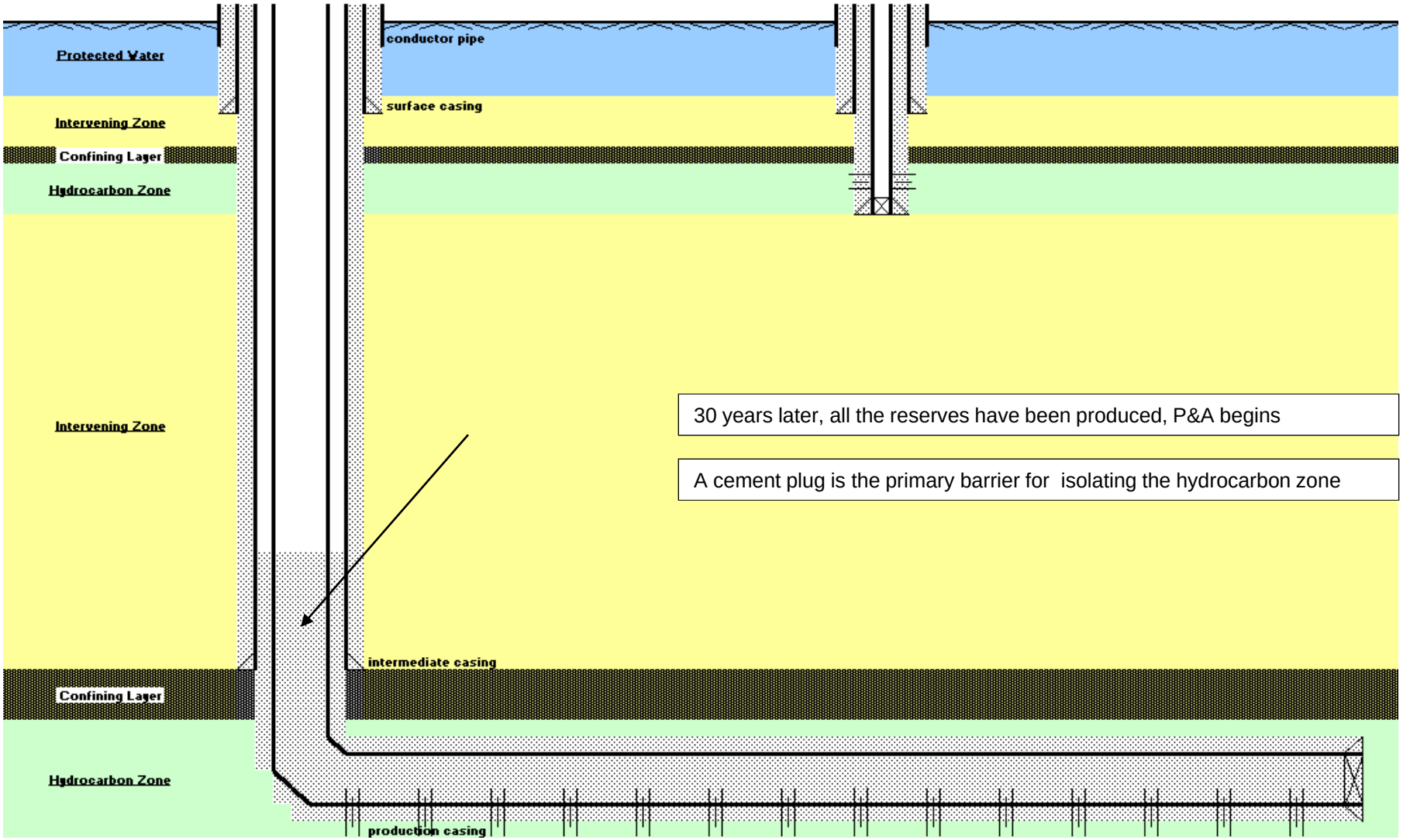
Slide 18 of 22 – Plug and Abandonment begins, producing zone is plugged and tested



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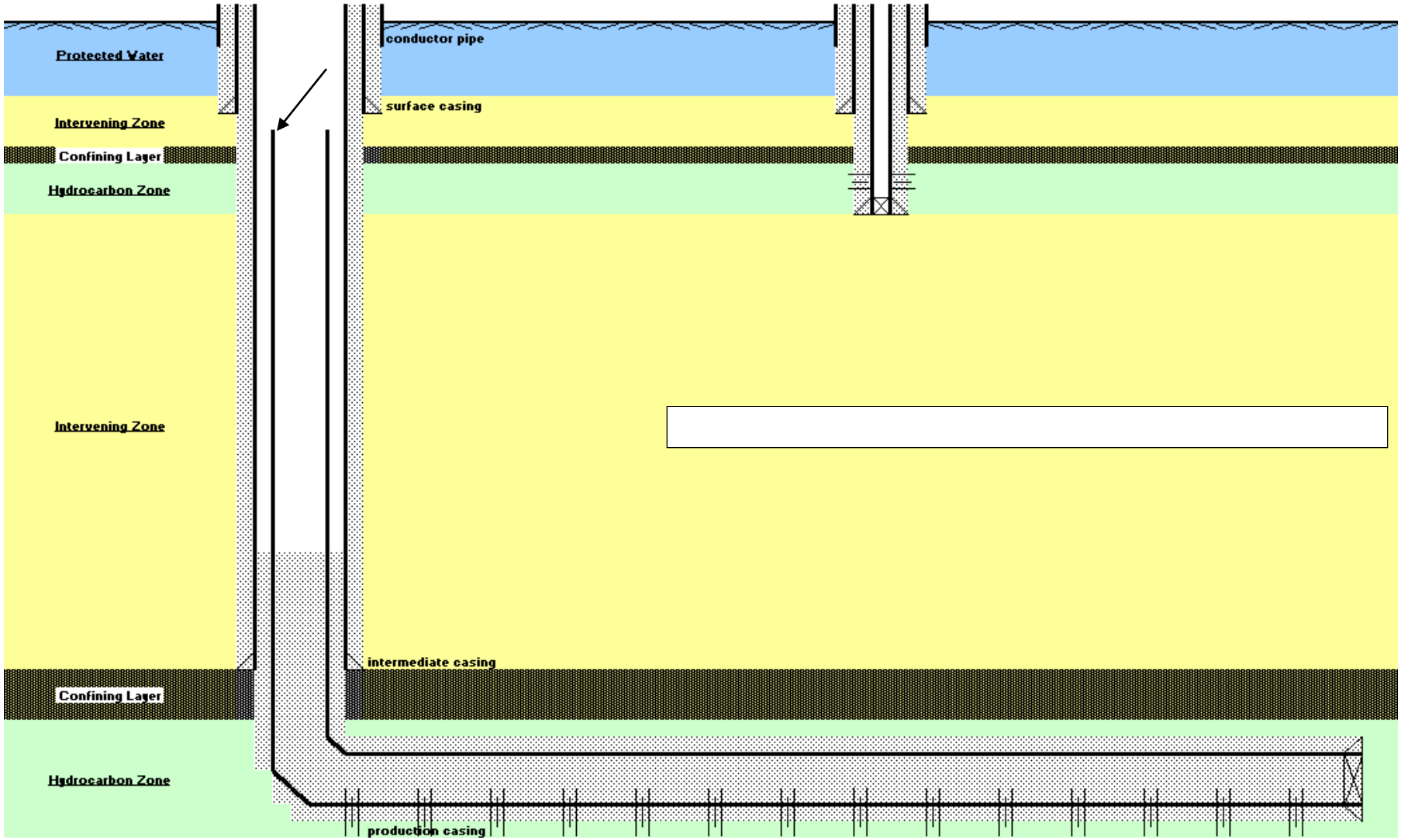
Slide 19 of 22 – Casing is cut or perforated near the surface casing shoe



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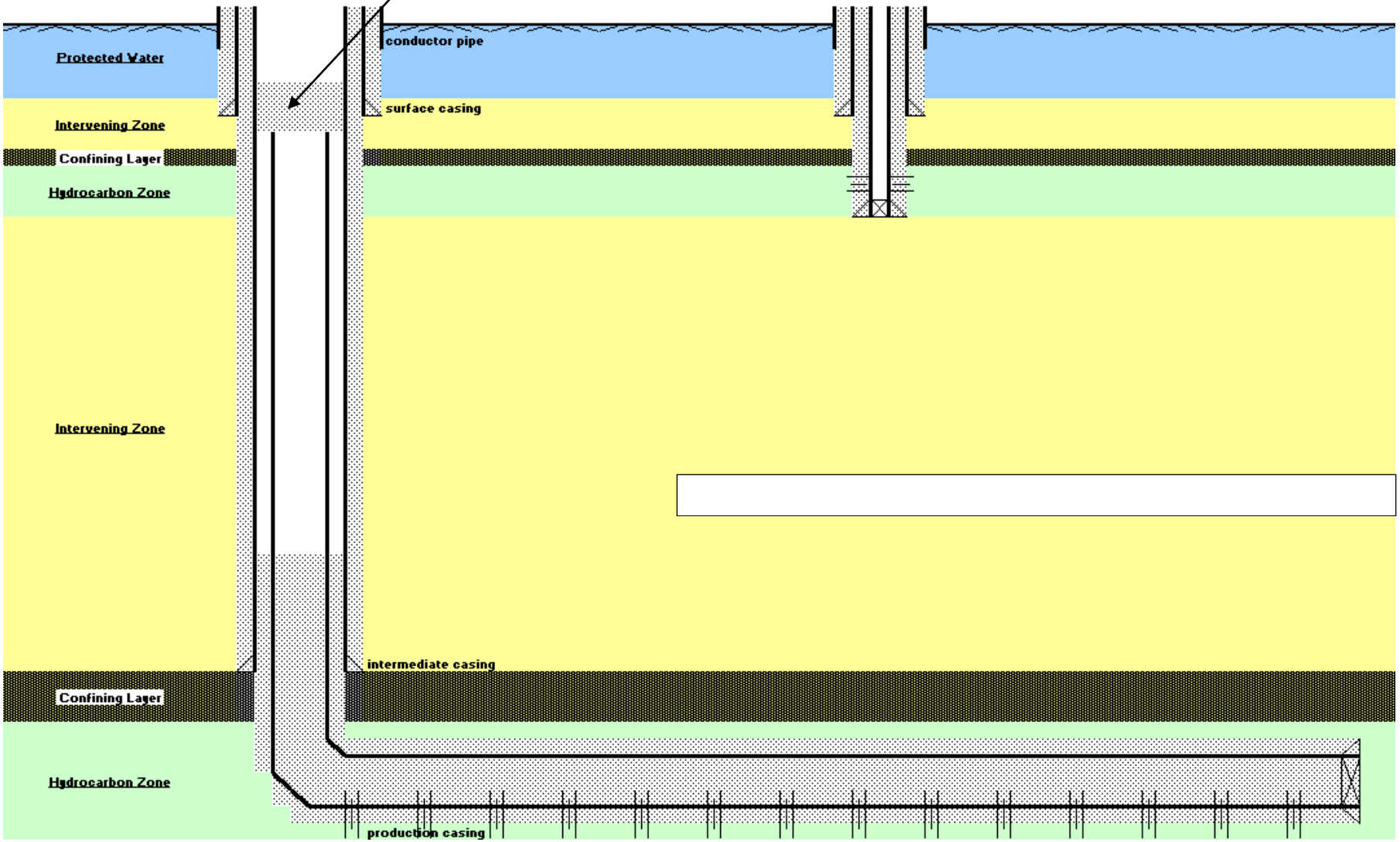
Slide 20 of 22 – Cement plug is set across the surface casing shoe and tested



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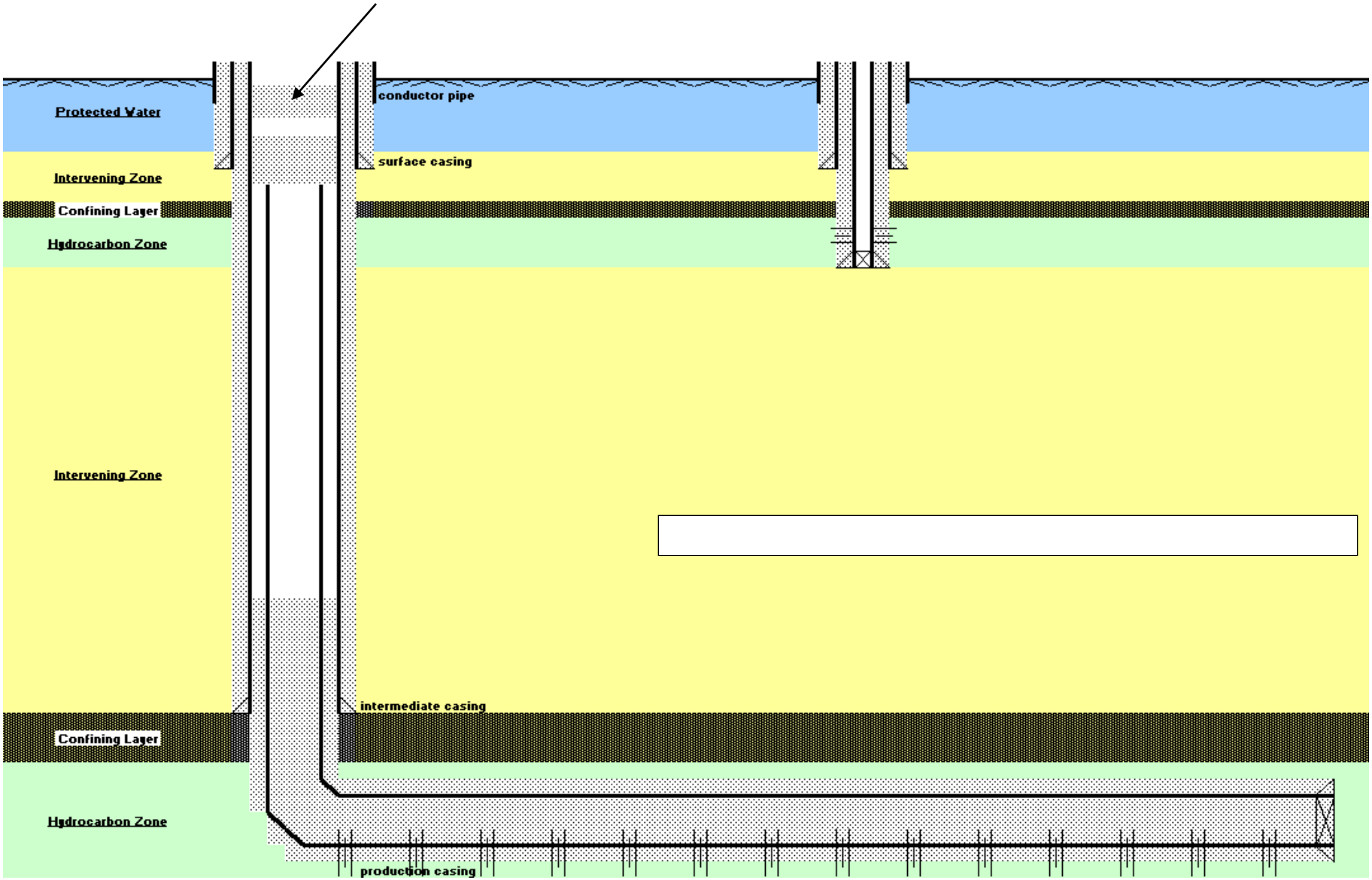
Slide 21 of 22 – Shallow surface plug is set and tested



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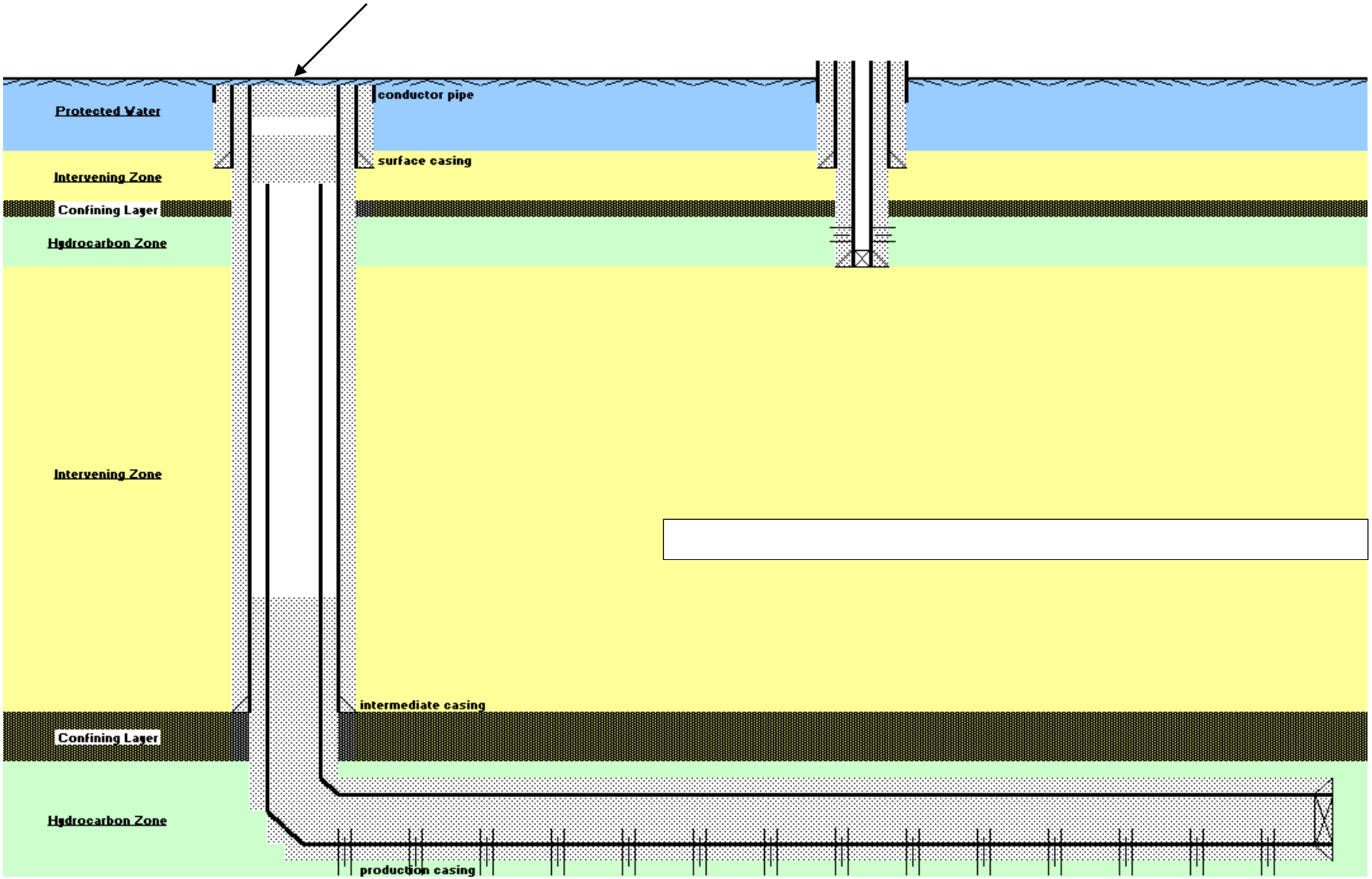
Slide 22 of 22 – Pipe cut-off, cap welded, well ID marker, backfill



Case Study for Well Integrity over a Full Life Cycle

Lloyd H. Hetrick, PE, CSP
Newfield Exploration Company

The statements made during the workshop do not represent the views or opinions of EPA. The claims made by participants have not been verified or endorsed by EPA.

Abstract

This case study narrowly defines well integrity by one simple outcome: the prevention of vertical migration of fluids in order to protect drinking water resources. This paper should not be considered a stand alone document, rather an extension of the well design, construction, and surveillance practices which have already been addressed in this Workshop. A generic shale development well is presented, beginning with its basis of design, then construction, an operational phase, and ultimately its plug and abandonment. This chronology is illustrated by a series of well schematics, which are provided in Appendix A.

Regulations, industry standards, and best practices will be addressed, as will failure categories and relative failure rates at each phase of the well's life cycle. This case study will also raise relevant issues that may not have been fully discussed during this Workshop, such as the difference between exploration and development phases, development well economics, the potential for well integrity impacts from adjacent well activities, and a time line perspective.

Introduction

A brief process description for oil and gas projects might be helpful. Years before a well is drilled, significant geological and geophysical "G&G" work is performed to identify prospective areas. During this time, offset wells are studied to identify subsurface hazards that may be present in order to avoid or mitigate them. Once a prospect is defined mineral leases are acquired, additional G&G and reservoir analysis performed, and well design determined for specific drilling locations. The first group of wells drilled are called "exploratory" and intended to define the commercial value of the prospect. Exploratory wells require extra time to gather data on the quality of the reservoir and are also used to identify well construction efficiencies for the development phase. Once the project transitions from exploration to development, each well has to pass an economic hurdle to be drilled.

Regardless of being exploratory or development, responsible oil and gas companies have a strong business incentive to protect the environment, mineral reserves, and the well itself (1). It is almost always more difficult and costly to re-enter and repair a well than to address design deficiencies up front during construction.

This case study, although generic, is not unlike the Marcellus, Eagle Ford, and other unconventional plays with multiple hydrocarbon zones. Even though only one reservoir is the current development objective, additional reservoirs are candidates for future development.

This case study will address technical issues but cannot explore very many technical details due to a fifteen minute presentation limit. Accordingly, only the most relevant technical items such as failure modes will be included and even then, will be greatly abbreviated. For example, if corrosion is considered to be the primary failure category, the technical discussion will end there with no deeper look into the true root cause failure mode such as galvanic corrosion, sulfide stress cracking, etc.

Federal and State environmental laws protect underground sources of drinking water or "USDWs". This paper will use USDW synonymously with the term "protected water" and refers to an aquifer with less than 10,000 mg/l total dissolved solids or "TDS" (2).

State mineral law regulates the extraction and conservation of minerals unless on Federal BLM or BIA land, then Federal mineral laws apply. In either case, the regulatory agency that oversees mineral extraction is also the primary regulator for protecting USDWs during oil and gas exploration and production activities (3) (4).

Protected water and hydrocarbons have natural separation (5) in most situations. There are however, areas of the country where methane is routinely found to exist naturally in USDWs (6) (7) and has been associated with bubbles in rivers as early as the mid 1800s (8). There are also locations where methane vents to the surface via natural pathways having nothing to do with oil and gas extraction activities (9) (10). It has been estimated from a review of Pennsylvania regulatory records that over 95% of the complaints that oil and gas activities had contaminated private water wells were actually due to preexisting or other land use activities (11). These naturally occurring migrations are not limited to methane, as towns named Oil Springs, KY (12) Oil Springs, Ontario (13) and historical sites such as Seneca Oil Spring, NY (14) and Brine Springs, TX (15) all attest that oil and brine have been observed migrating to the surface dating back to the 1600's.

Basis of Design

A development well is drilled only if there is confidence that the estimated recoverable hydrocarbon reserves will provide an acceptable economic rate of return, given the cost to construct and operate the well. For an unconventional gas play, development wells tend to have generational designs where a group of wells will have a similar drilling, casing, cementing, perforating, and hydraulic fracturing design. Over time as more wells are drilled, experience provides opportunities to correct any design deficiencies, improve drilling efficiencies and well performance, therefore subsequent generations of wells are seldom designed exactly the same.

Individual wells, regardless of their generational status, receive detailed engineering analysis and planning which is communicated to the wellsite supervisor in the form of a written drilling and completion procedure. These well specific procedures are a planned sequence of activities which also incorporate regulatory compliance and industry best practices.

Well Construction - Drilling

A typical onshore well is spud with a conductor pipe that is driven, drilled, or augered into the ground by a construction crew or "spud rig" prior to the drilling rig's arrival. This conductor pipe is a structural component that sometimes is not needed at all. Conductor pipe most often does not reach the top and does not penetrate the base of protected water; therefore it is not involved in protecting USDWs from vertical migration of fluids. Accordingly, failure categories for the conductor pipe will not be discussed.

The surface hole is drilled to a prescribed depth below the base of protected water. This depth is most often provided by the State Oil and Gas Regulator as in Oklahoma (16), or the State Environmental Protection Regulator as in Texas (17), or not specifically provided other than to protect all USDWs encountered as in Pennsylvania (18). In this latter situation, oil and gas operators typically research a Pennsylvania Groundwater Information System "PaGWIS" database and local water well driller's records to generate a hydro geological map in order to determine depths of water that need to be protected.

The surface hole is not left open for more than a few hours while being drilled, cased, and then cemented back to surface. Those zones left open during this brief period are all USDWs, so vertical migration of fluids does not present a significant threat during surface hole drilling. The surface hole on our case study well is drilled in a few hours on the first day of the drilling operation.

The surface casing string is the primary barrier to prevent fluids from the wellbore from entering protected water as the well is being drilled to the next casing setting depth. Unlike the conductor pipe, surface casing is always required and is typically specified by regulation to be of "suitable and sufficient" quality (19) or "suitable for all drilling and operating conditions such as tension, burst, collapse" (20). For all casing strings, industry best practices provide extensive guidance on the selection of proper casing size, grade, weight, connections, plus procedures for field handling, inspection, and testing (21) (22) (23) (24) (25) (26) (27). For our case study well, the surface casing is "run" or installed in a few hours during day #1 of the drilling operation.

Failure categories for the surface casing and all other casing strings can be divided into the following five categories (28). It should be noted that two of these categories, mechanical and corrosion, may be secondary to cement failures where a failed cement sheath can lead to buckling or external corrosion that would not have otherwise occurred. Failure categories, their respective failure modes, relative failure rates, and remedial options will be discussed briefly:

- Materials – defects, tolerance busts, not getting the quality of pipe specified
- Connections – wrong connection selected for the service, improper makeup
- Wear and Handling – internal wear from drilling, external damage from handling
- Mechanical – tensile, burst, collapse, buckling, cyclic loading
- Corrosion – internal vs external; galvanic, CO_2, sulfide stress, hydrogen induced cracking

Materials defects are supplier dependent and can be managed by inspections and other supply chain quality control efforts. Connection problems are most often related to improper makeup and can be minimized by onsite supervision. Wear for the surface casing string is seldom a concern and occurs as a result of other problems encountered while drilling the well. Mechanical problems with the surface casing are very few when compared to deeper casing strings that are exposed to higher pressures and temperatures. External corrosion presents the highest failure category for surface casing. Remedies may include external coatings, cement squeezes, and cathodic protection systems.

The surface casing string's cement job provides the primary barrier against vertical migration of fluids into protected water for the entire life of the well. In the context of USDW protection, the importance of getting a good primary cement job on the surface casing string cannot be overstated. Remedial cementing options do not provide high success rates for zonal isolation and should be considered only for contingency purposes. Of all regulations for onshore wells, the rules for surface casing cementing contain the most stringent requirements for hole size vs casing size, centralization, cement quality, cement quantity, cement placement techniques, and quality assurance than for any other casing string (29). Failure to properly cement the surface casing string triggers both agency notification and corrective actions (30). The surface casing on our case study well is cemented on day #2 of the drilling operation.

There is a significant body of information published on cement selection and cementing best practices (31) (32) (33) (34). There is also a significant body of information available on cementing failure rates (35) (36). This Well Integrity Case Study will focus on those conditions which directly relate to zonal isolation for the protection of USDWs, briefly discussing three failure categories, with their respective modes and relative failure rates, and remedial options:

- Insufficient cement volume – underestimated annular volume, lost circulation
- Low bond strength – poor slurry design, poor management of hydrostatic head pressure
- Micro annulus, cracking, plastic deformation – thermal and pressure effects, cyclic loads

Cement failure rates are directly proportional to the ability to evaluate the top of and quality of the cement sheath. Cement tops can be identified by a temperature log, relative cement bond quality can be identified by a Cement Bond Log or CBL, while absolute cement bond quality requires a combination of logging, testing, and engineering analysis (37).

For all three cement failure categories, remedial options are not optimum and include pumping in from the top, spotting from the top via a small work string, or by perforating and squeezing. It should be noted that two of these three remedies, pumping in from the top and perforating and squeezing, might add new problems for zonal isolation if not properly executed.

There is a strong correlation between gas migration and uncemented or poorly cemented casing strings. There is also a strong correlation between external casing corrosion and the absence of a good cement sheath (35) (36).

After the surface casing has been successfully tested, the float collar, float shoe, and approximately 10' of new formation are drilled. Another integrity test is then performed, a Formation Integrity Test or "FIT" which tests both the casing shoe and new formation together. This is not a leak-off test and does not test the limits of the shoe and formation, rather the FIT provides an assessment of the wellbore's ability to withstand additional pressure in case of an influx of fluids and allows for safer drilling to the next casing point (38).

The next sections of well, which for this case study includes an intermediate and production casing section, are essentially a repeat of the surface casing section described above except that:

- The design depth for intermediate and production casing strings are not as comprehensively regulated (as for the surface casing depth) other than to provide safe drilling operations and to prevent the waste of minerals.
- The regulations concerning hole size vs casing size, centralization, cement quality, cement quantity, cement placement techniques, and quality assurance for intermediate and production casing strings are not as specific (as for the surface casing) other than to provide safe drilling operations and prevent the waste of minerals.

Although this case study well has been drilled, cased, and cemented over a 30 day period, the first two days are the most critical for zonal isolation of USDWs where the foundation for well integrity is determined.

Well Construction - Completion

Well completion is the where the production casing is perforated, the formation is hydraulically fractured, frac fluids are unloaded from the formation, and production operations commence. This is basically the well's configuration for the rest of its life as it relates to protecting USDWs.

Prior to performing the hydraulic frac, the production casing is tested to anticipated frac pressure plus a safety factor, as is the frac tree and all the surface pumping equipment and lines. During the frac, all casing annuli are monitored, as is the injection rate, injection pressure, and slurry properties. If during the frac job, significant pressure is found on the intermediate casing annulus, or there is any indication of communication with the surface casing annulus, the frac job is shut down and not resumed until corrective actions are made that only the intended zone is subject to frac pressures.

Refracs are similar to original fracs as discussed above with the exception that a frac string or wellhead saver might be used to protect older production casing strings and wellheads from frac pressures. This is a case by case situation that requires additional testing and engineering analysis in order to protect both the well and USDWs during refrac operations.

As the well is produced, reservoir pressures tend to drop and liquid rates tend to rise, therefore devices for lifting liquids such as a tubing string with pumping or gas lift equipment becomes

necessary. This internal configuration can have an impact on USDW protection and is addressed during the operations phase.

Well Operations

Prudent operators monitor all casing annuli on a regular basis to be able to detect sustained casing pressure or SCP. This condition could be caused by thermal expansion of annular fluids, packer or liner leaks, leaks into the annulus from inner tubing or casing strings, or from annular migration due to poor zonal isolation.

All states have rules for reporting and responding to the loss of well integrity which includes releases, non-thermal SCP, and other abnormal situations (39) as does the BLM (40) and best industry practices (41). The Commonwealth of Pennsylvania has new rules that require quarterly mechanical integrity testing and annual reporting for all operating wells (42).

Adjacent well operations may have an impact on mechanical integrity of our case study well. Hydraulic fracturing of a well near our case study well into a zone that is not protected, or not adequately protected for the conditions imposed can lead to unwanted well to well communication. This is currently a void where regulations and industry practices have not fully recognized that well integrity can become a neighborhood issue.

Well Plug and Abandonment "P&A"

Similar to well construction regulations and industry practices, well P&A also has comprehensive guidance to prevent vertical migration of fluids into USDWs. There is clear guidance for plug location, cement quantity, quality, placement techniques, testing, and reporting (43) (44) (45). Regulations may also specify that only approved cementing contractors perform plugging, require independent onsite supervision, and require post cement job certifications by both the operator and the cementing company.

There are also significant industry studies and best practices for well P&A (46) (47).

Failure studies have found that vertical migration issues in P&Aed wells are directly related to the original primary cement job during well construction. Those wells with gas migration to the surface prior to well P&A were likely to continue to have gas migration to the surface after P&A. Additionally, those wells plugged with bridge plugs and dump bailed cement on top were found to be more prone to leakage than wells plugged with cement that was circulated or squeezed in place (35) (36).

Conclusions

Well integrity and well construction are inextricably linked, regardless of the completion technique selected. Primary cementing is the critical step for preventing vertical migration of fluids during the well's productive life, and afterwards.

State and federal regulations address casing and cementing with prescriptive rules and reporting requirements, while industry employs a large body of technical studies and best

practices. Five identified casing failure categories: materials, connections, wear / handling, mechanical, and corrosion are not as problematic for zonal isolation as three identified cementing failure categories: insufficient cement volume, low bond strength, and cement sheath damage.

For hydraulically fractured completions, significant bodies of industry technical information and best practices have been published. State and federal regulations address hydraulic fracturing with rules and reporting requirements which are continuously adapting to keep pace with technology advancements (48).

Adjacent wells and the potential for unwanted communication during hydraulic fracturing is a concern. State and federal regulations are largely silent on this issue, as are industry studies and best practices.

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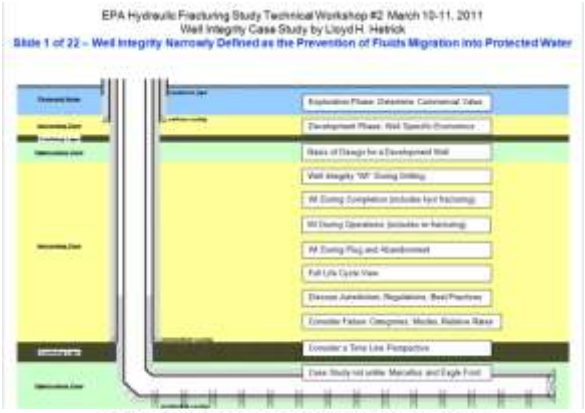
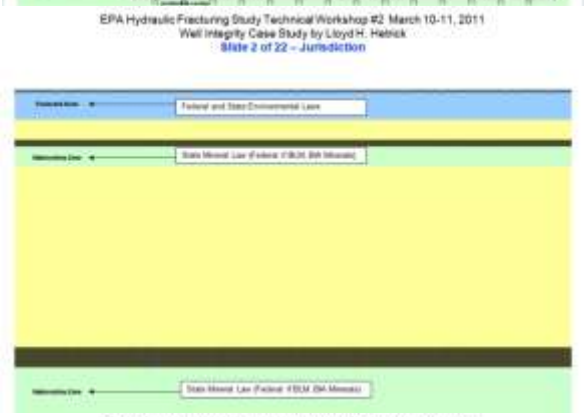
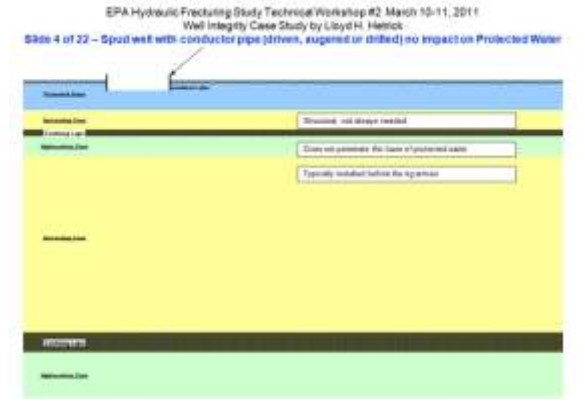
Appendix A – PowerPoint Illustration for this Well Integrity Case Study – Slides 1 through 4







Appendix A – PowerPoint Illustration for this Well Integrity Case Study – Slides 5 through 8

EPA Hydraulic Fracturing Study Technical Workshop #2 March 10-11, 2011
Well Integrity Case Study by Lloyd H. Hetrick
Slide 5 of 22 – Well is drilled to a prescribed depth below Protected Water

EPA Hydraulic Fracturing Study Technical Workshop #2 March 10-11, 2011
Well Integrity Case Study by Lloyd H. Hetrick
Slide 6 of 22 – Surface casing is run

EPA Hydraulic Fracturing Study Technical Workshop #2 March 10-11, 2011
Well Integrity Case Study by Lloyd H. Hetrick
Slide 7 of 22 – Surface casing is cemented and tested

EPA Hydraulic Fracturing Study Technical Workshop #2 March 10-11, 2011
Well Integrity Case Study by Lloyd H. Hetrick
Slide 8 of 22 – Surface casing shoe and formation are integrity is tested

Appendix A – PowerPoint Illustration for this Well Integrity Case Study – Slides 9 through 12

EPA Hydraulic Fracturing Study Technical Workshop #2 March 10-11, 2011
Well Integrity Case Study by Lloyd H. Hetrick
Slide 9 of 22 – Next section of hole is drilled

EPA Hydraulic Fracturing Study Technical Workshop #2 March 10-11, 2011
Well Integrity Case Study by Lloyd H. Hetrick
Slide 10 of 22 – Intermediate string of casing is run

EPA Hydraulic Fracturing Study Technical Workshop #2 March 10-11, 2011
Well Integrity Case Study by Lloyd H. Hetrick
Slide 11 of 22 – Intermediate casing is cemented and tested

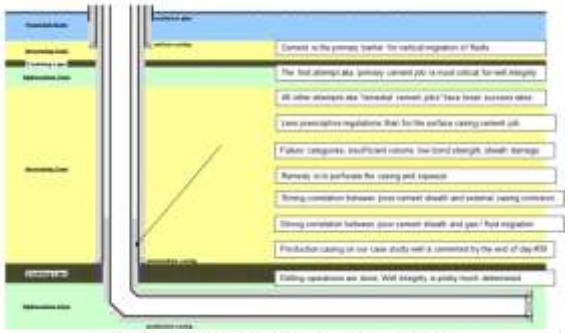
EPA Hydraulic Fracturing Study Technical Workshop #2 March 10-11, 2011
Well Integrity Case Study by Lloyd H. Hetrick
Slide 12 of 22 – Intermediate casing shoe and formation integrity are tested

Appendix A – PowerPoint Illustration for this Well Integrity Case Study – Slides 13 through 16

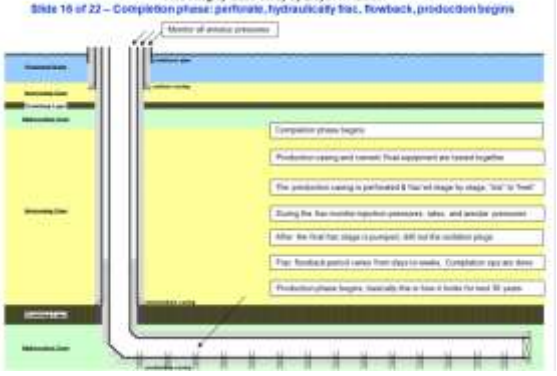
EPA Hydraulic Fracturing Study Technical Workshop #2 March 10-11, 2011
Well Integrity Case Study by Lloyd H. Hetrick
Slide 13 of 22 – Next section of hole is drilled

EPA Hydraulic Fracturing Study Technical Workshop #2 March 10-11, 2011
Well Integrity Case Study by Lloyd H. Hetrick
Slide 14 of 22 – Production casing is run

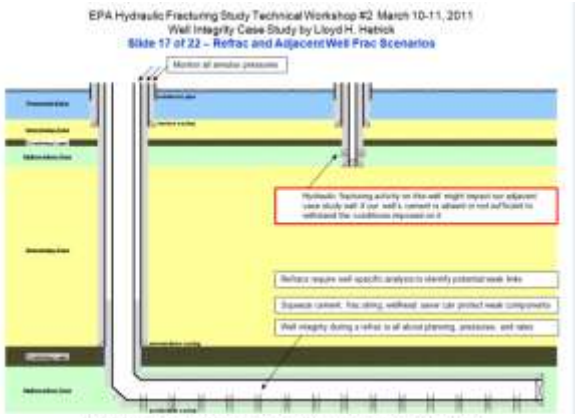
EPA Hydraulic Fracturing Study Technical Workshop #2 March 10-11, 2011
Well Integrity Case Study by Lloyd H. Hetrick
Slide 15 of 22 – Production casing is cemented. Drilling phase is done

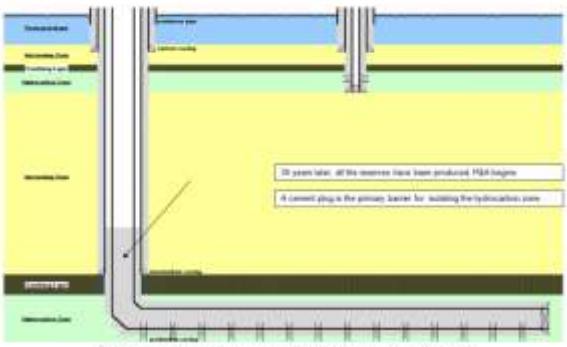


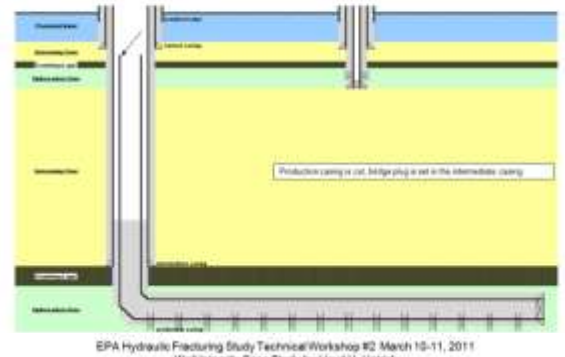
EPA Hydraulic Fracturing Study Technical Workshop #2 March 10-11, 2011
Well Integrity Case Study by Lloyd H. Hetrick
Slide 16 of 22 – Completion phase: perforate, hydraulically frac, flowback, production begins

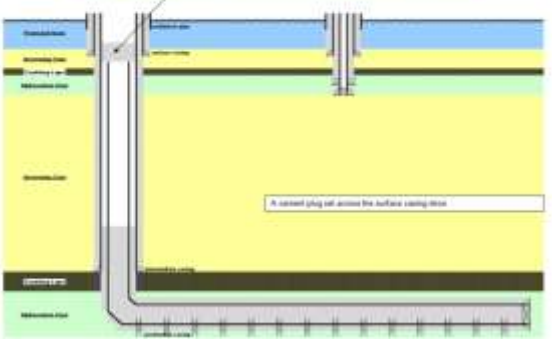


Appendix A – PowerPoint Illustration for this Well Integrity Case Study – Slides 17 through 20









Appendix A – PowerPoint Illustration for this Well Integrity Case Study – Slides 21 through 22