A Review on Effects of Fluid Saturation on Seismic Velocity, Attenuation, and Dispersion in Reservoir Rocks

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Abstract:
Fluid saturation strongly influences seismic wave propagation in reservoir rocks and is therefore important for hydrocarbon characterization, time-lapse monitoring, and geological CO_2 storage. This review examines how fluid type, saturation level and distribution, pore structure, permeability, effective pressure, and frequency control seismic velocity, attenuation, and dispersion. P-wave velocity is generally more sensitive to fluid substitution than S-wave velocity because pore fluids directly modify the saturated bulk modulus. Under partial saturation, however, average saturation alone cannot uniquely determine seismic response because heterogeneous and patchy fluid distributions generate spatial pore-pressure contrasts. Wave-induced fluid flow driven by these contrasts causes viscous energy dissipation and seismic attenuation, while incomplete pressure equilibration produces frequency-dependent velocity dispersion. Experimental, theoretical, and numerical studies show that the characteristic response is strongly controlled by saturation geometry, fluid properties, permeability, and measurement frequency. Joint interpretation of velocity, attenuation, and dispersion therefore provides a more complete framework for reservoir-fluid characterization than velocity alone. Future advances require broadband measurements, three-dimensional fluid imaging, digital rock physics, and coupled multiphase-flow and poroelastic modeling to improve quantitative saturation estimation from laboratory to field scales.

Keywords: Fluid saturation; reservoir rocks; seismic velocity; seismic attenuation; velocity dispersion; wave-induced fluid flow; patchy saturation; rock physics.

1. Introduction and Fundamental Rock-Physics Framework

1.1 Background and Significance
Seismic properties of reservoir rocks are controlled by both the solid rock framework and the fluids occupying the pore space. Changes in water, oil, gas, or CO_2 saturation can modify seismic velocity, attenuation, and frequency-dependent dispersion, making these properties important for hydrocarbon characterization, reservoir monitoring, and geological CO_2 storage. Fluid effects depend not only on saturation level but also on fluid compressibility, viscosity, density, pore structure, permeability, effective pressure, and saturation distribution. P-wave velocity is generally more sensitive to pore-fluid changes than S-wave velocity because fluids directly influence the saturated bulk modulus. Partial saturation introduces additional complexity because different fluids may be distributed heterogeneously within the pore network. Early experimental studies demonstrated substantial differences in seismic behavior among dry, partially saturated, and fully saturated rocks [1-5]. Consequently, saturation percentage alone cannot uniquely describe seismic response. Fluid distribution and the ability of pore pressure to equilibrate during wave propagation are also important, particularly for understanding attenuation and dispersion [9, 10, 18-20].

1.2 Fluid Saturation and Distribution
Fluid saturation represents the fraction of pore volume occupied by a particular fluid. In a two-phase water-gas system,

$$S_w + S_g = 1$$

Where S_w and S_g are water and gas saturation, respectively. Reservoirs may also contain water, oil, and gas simultaneously, while geological CO_2 storage formations commonly contain brine and CO_2.
Different fluids produce different seismic responses because their elastic properties differ. Gas is much more compressible than water or oil and can therefore cause a substantial reduction in the effective bulk modulus and P-wave velocity. Liquid-to-liquid substitutions generally produce smaller contrasts. The spatial distribution of these fluids is equally important. Under fine-scale or approximately uniform saturation, pore pressures can equilibrate relatively efficiently. Under patchy

saturation, fluids occupy separate regions and may develop different pore pressures during seismic deformation. The resulting pressure gradients can drive fluid movement and produce attenuation and velocity dispersion [13, 19-23]. Thus, seismic behavior depends on both **how much fluid is present and how that fluid is distributed**.

1.3 Seismic Waves in Fluid-Saturated Porous Rocks

Biot's poroelastic theory provides the fundamental framework for describing wave propagation in fluid-saturated porous media [1–4]. A saturated rock is treated as a coupled system consisting of a deformable solid framework and mobile pore fluid. Seismic deformation generates changes in pore pressure, while relative motion between the fluid and solid can dissipate seismic energy. The effect is particularly important for compressional waves. P-wave propagation involves volumetric deformation and is therefore sensitive to the compressibility of the pore fluid. S waves are less directly affected because fluids do not sustain static shear stress. Heterogeneous rocks can develop local pore-pressure differences during seismic deformation. Fluid movement driven by these gradients is known as **wave-induced fluid flow (WIFF)** and is one of the principal mechanisms responsible for fluid-related attenuation and dispersion [14,18].

Frequency is critical because it determines how much time is available for pressure equilibration. At low frequencies, fluid has more time to redistribute, whereas at higher frequencies fluid movement becomes increasingly restricted. Therefore, seismic properties measured at field, sonic, and ultrasonic frequencies may differ even for the same rock and saturation condition.

1.4 Fluid Saturation and Effective Elastic Properties

For an isotropic saturated rock, seismic velocities can be expressed as

$$V_P = \sqrt{\left[\frac{K_{sat} + \frac{4G}{3}}{\rho}\right]}$$

and

$$V_S = \sqrt{\frac{G}{\rho}},$$

Where K_{sat} is the saturated bulk modulus, G is the shear modulus, and ρ is bulk density.

These relationships explain why P-wave velocity is particularly sensitive to fluid substitution. Changing the pore fluid modifies the saturated bulk modulus and density, whereas the shear modulus is much less directly affected.

Under partial saturation, however, effective elastic properties cannot always be predicted from average saturation alone. Uniform and patchy fluid distributions can produce different effective moduli. Furthermore, incomplete pressure equilibration between fluid regions creates frequency-dependent stiffness. The rock may exhibit a relatively compliant response at low frequency and a stiffer response at high frequency, producing velocity dispersion together with attenuation [14, 18–20].

Velocity, attenuation, and dispersion should therefore be considered interconnected manifestations of fluid-rock interaction rather than independent seismic properties.

1.5 Scope of the Review

This review evaluates the influence of fluid saturation on **seismic velocity, attenuation, and dispersion in reservoir rocks**. Particular attention is given to partial and patchy saturation, wave-induced fluid flow, frequency dependence, and the effects of fluid and pore properties. Experimental, theoretical, and numerical studies are considered to identify the principal controls on saturation-dependent seismic behavior.

The review will further examines the application of these relationships to hydrocarbon reservoir characterization, time-lapse seismic monitoring, and geological CO_2 storage, also will be highlighting current modeling limitations and future research needs.

2. Effects of Fluid Saturation on Seismic Velocity

2.1 P-Wave Velocity Response to Saturation

P-wave velocity (V_p) is highly sensitive to pore-fluid saturation because compressional deformation involves changes in pore volume and fluid pressure. Replacing a compressible fluid such as gas with water or oil generally increases the saturated bulk modulus and therefore increases V_p. Conversely, introducing gas into a liquid-saturated rock can produce a substantial velocity reduction because the bulk modulus of gas is much lower than that of reservoir liquids [5,10,11]. The response is commonly nonlinear under partial saturation. A relatively small gas fraction may cause a pronounced reduction in V_P, particularly when gas is finely distributed throughout the pore space. At higher water saturation, the response depends increasingly on whether the remaining gas is uniformly distributed or concentrated into patches [13,17,20].

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$$V_P = \sqrt{\left[\frac{K_{sat}+\frac{4G}{3}}{\rho}\right]},$$

Where K_sat is the saturated bulk modulus, G is the shear modulus, and ρ is bulk density. Fluid saturation therefore affects V_P mainly through changes in K_sat and, to a lesser extent, density.

2.2 S-Wave Velocity and V_p/V_s Response

S-wave velocity is generally less sensitive to fluid substitution because pore fluids cannot sustain static shear stress. It is given approximately by

$$V_S = \sqrt{\frac{G}{\rho}}.$$

If the rock frame remains unchanged, fluid substitution affects V_s primarily through density rather than shear modulus. Consequently, changes in V_s are usually smaller than corresponding changes in V_p.

However, saturation-related variations in effective stress, compliant cracks, clay-fluid interactions, and pore structure can indirectly alter the shear response. This is particularly relevant in fractured, poorly consolidated, and stress-sensitive reservoir rocks.

The different sensitivities of P and S waves make the V_p/V_s ratio useful for fluid discrimination. Gas saturation can strongly decrease V_p while producing a comparatively small change in V_s, resulting in a characteristic change in V_p/V_s. Nevertheless, lithology and pressure must be considered before such changes are attributed solely to fluid saturation.

2.3 Partial Saturation and Fluid Distribution

Partial saturation produces more complex velocity behavior than complete single-fluid saturation because seismic response depends on both **saturation fraction and spatial fluid distribution**. Two limiting conditions are commonly considered. Under fine-scale or uniform saturation, fluids are distributed over sufficiently small distances for pore-pressure equilibration to occur efficiently. Under patchy saturation, regions dominated by different fluids remain spatially separated and can respond differently during seismic compression [13,19,20]. As a result, two rocks with identical average water saturation may have different P-wave velocities. Patch size, connectivity, and fluid contrast determine how strongly the saturation geometry influences the effective modulus. This explains why a simple relationship of the form

saturation → velocity

is often inadequate. A more realistic interpretation is

fluid type + saturation level + saturation distribution → effective elastic properties → seismic velocity.

2.4 Frequency and Pressure-Equilibration Effects

Velocity in partially saturated rocks may also depend on measurement frequency. Seismic compression creates pore-pressure differences between regions containing fluids of different compressibilities. Whether these pressures can equilibrate depends on permeability, viscosity, characteristic flow distance, and wave period [14,18]. At low frequencies, pressure has sufficient time to redistribute, producing a relatively relaxed and compliant elastic response. At higher frequencies, fluid exchange becomes restricted and different saturation regions respond more independently, increasing the effective stiffness and seismic velocity. The transition between these states produces velocity dispersion. This frequency dependence is important when comparing measurements from different scales. Surface seismic data commonly occupy frequencies of tens to hundreds of hertz, sonic logs operate at higher frequencies, and laboratory ultrasonic measurements may reach hundreds of kilohertz or megahertz. Therefore, laboratory velocity measurements cannot always be transferred directly to field conditions without considering dispersion.

2.5 Influence of Rock and Fluid Properties

The magnitude of the saturation effect varies substantially among reservoir rocks. Important controls include porosity, permeability, frame stiffness, pore geometry, fractures, mineralogy, effective pressure, and fluid properties. High porosity increases the volume occupied by fluids, but fluid sensitivity also depends on frame stiffness. A compliant rock frame can respond strongly to fluid substitution, whereas a stiff, well-cemented frame may reduce the relative effect of pore fluids. Permeability controls the rate of pore-pressure equilibration and is therefore especially important for frequency-dependent behavior. Pore geometry and fractures determine characteristic flow distances and may introduce additional fluid-flow mechanisms. Effective pressure alters grain contacts and compliant cracks, potentially producing velocity changes that can be confused with saturation effects. Fluid properties are equally important. Gas-liquid substitution generally produces a much stronger seismic contrast than oil-water substitution because of the large difference in compressibility. Fluid viscosity influences pressure diffusion and becomes particularly important when frequency-dependent effects are considered. Carbonates,

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tight rocks, fractured reservoirs, and conventional sandstones can therefore exhibit different saturation-velocity relationships even under similar fluid conditions [23,24].

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Table 3.1. Principal Controls on Saturation-Dependent Seismic Velocity

Factor	Main influence on seismic velocity
Fluid bulk modulus	Major control on P-wave response; gas produces particularly strong effects
Saturation level	Determines relative proportions of pore fluids
Saturation distribution	Uniform and patchy saturation can produce different velocities at the same average saturation
Rock-frame stiffness	Controls the relative sensitivity of the rock to fluid substitution
Porosity	Determines the volume available for pore fluids
Permeability	Controls pressure equilibration and frequency dependence
Pore/crack geometry	Controls compliance and fluid-flow length scales
Effective pressure	Alters grain contacts and crack compliance
Fluid viscosity	Influences pressure diffusion and dynamic fluid response
Frequency	Determines whether the measured response is relaxed, transitional, or unrelaxed

Overall, P-wave velocity provides strong sensitivity to fluid saturation, whereas S-wave velocity is generally less directly affected. However, **average saturation alone is insufficient to predict seismic velocity reliably**. Fluid type, spatial distribution, pore structure, pressure, and frequency must be considered together, particularly in partially saturated and heterogeneous reservoirs.

3. Fluid-Saturation Effects on Seismic Attenuation and Dispersion

3.1 Seismic Attenuation and Dispersion

Seismic attenuation represents the loss of wave energy during propagation and is commonly expressed by the inverse quality factor, Q^{-1}. In reservoir rocks, attenuation may arise from scattering, frictional losses, and fluid-related mechanisms. Among these, viscous movement of pore fluids is particularly important because it directly links attenuation to saturation, permeability, pore structure, and fluid properties [5–9,18]. Laboratory studies have consistently shown that dry, partially saturated, and fully saturated rocks can exhibit markedly different attenuation [5–11]. Partial saturation is especially important because fluids with contrasting compressibilities generate heterogeneous pore-pressure responses during seismic deformation. Attenuation is physically connected to **velocity dispersion**, which describes the variation of seismic velocity with frequency. When fluid-pressure redistribution changes the effective elastic modulus of the rock, the modulus becomes frequency dependent. The rock consequently exhibits different velocities at low and high frequencies. The frequency interval over which the modulus changes is generally accompanied by enhanced attenuation [14,18]. Thus, attenuation and dispersion provide complementary information:

Attenuation reflects energy dissipated during fluid redistribution, whereas dispersion reflects the associated frequency-dependent change in elastic stiffness. Their combined interpretation can therefore provide information about fluid behavior that cannot be obtained from a single velocity measurement.

3.2 Wave-Induced Fluid Flow Mechanisms

Wave-induced fluid flow (WIFF) is a major mechanism responsible for attenuation and dispersion in fluid-

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saturated heterogeneous rocks [14,18]. Seismic deformation does not necessarily generate identical pore-pressure changes throughout a reservoir rock. Differences in pore compliance, fluid compressibility, saturation, and local rock properties create pressure gradients that drive fluid movement. Because pore fluids possess viscosity, this movement is resisted by the pore network. Part of the seismic energy is consequently converted into heat, resulting in intrinsic attenuation. The accompanying redistribution of pore pressure changes the effective stiffness and produces velocity dispersion. The general mechanism can be summarized as:

Seismic deformation → heterogeneous pore pressure → fluid flow → viscous energy dissipation → attenuation + elastic dispersion.

WIFF can operate over different spatial scales. At the pore scale, pressure gradients may develop between compliant cracks and relatively stiff pores. This process is often associated with local or squirt-type fluid flow. At mesoscopic scales, fluid movement occurs between heterogeneous regions larger than individual pores but smaller than the seismic wavelength. Patchy saturation is one of the most important causes of such mesoscopic flow. At larger scales, fractures, layers, and reservoir heterogeneity can also generate pressure gradients. The characteristic length scale is critical because it determines the time required for pressure diffusion. Small-scale heterogeneities generally equilibrate more rapidly, whereas larger patches require longer diffusion times. Consequently, different WIFF mechanisms may dominate at different frequencies.

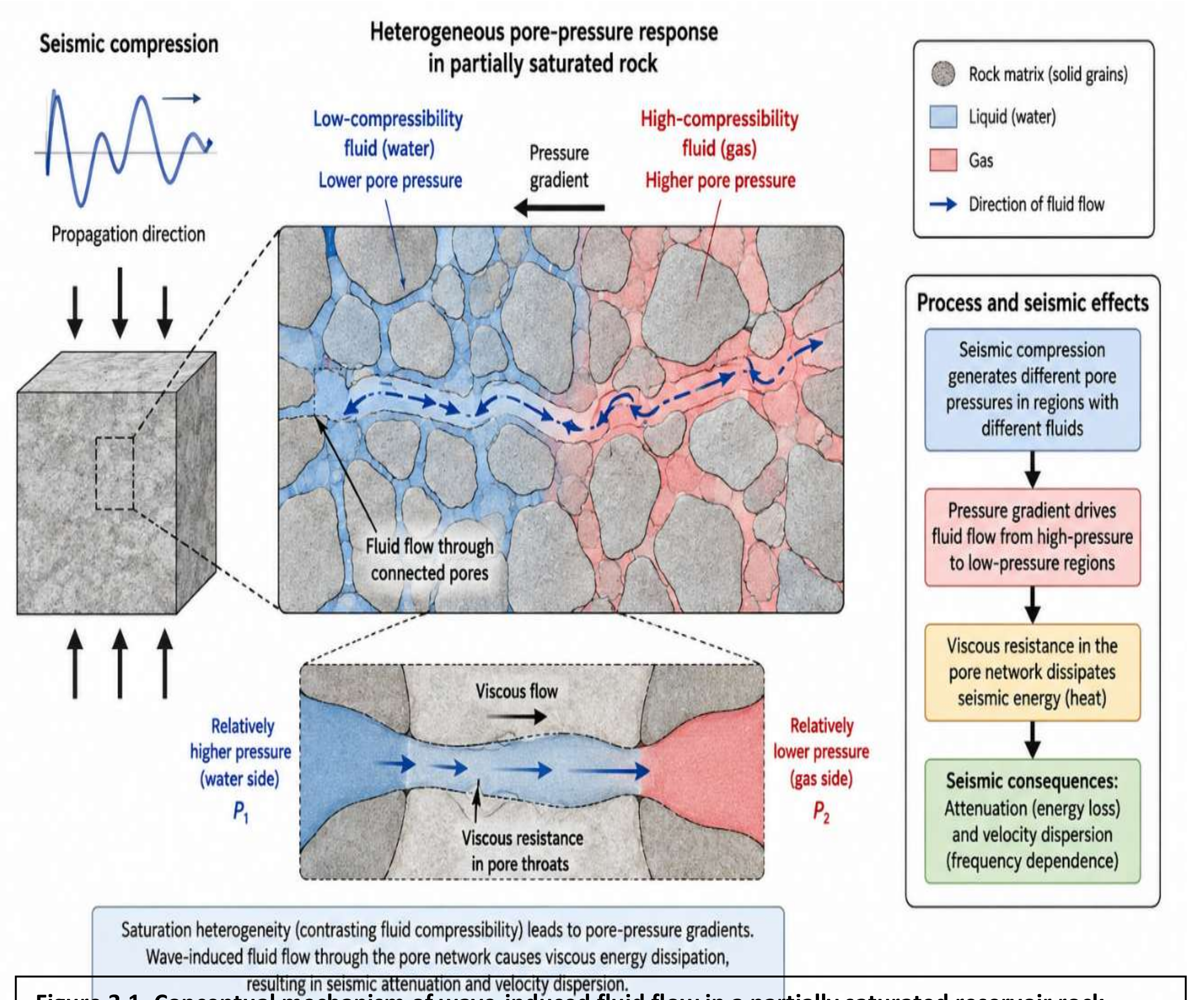

Figure 3.1. Conceptual mechanism of wave-induced fluid flow in a partially saturated reservoir rock

Table 3.2. Major Fluid-Related Attenuation and Dispersion Mechanism

Mechanism	Characteristic scale	Physical origin	Main controlling factors	Main seismic response
Biot-type flow	Macroscopic pore network	Relative motion between pore fluid and solid frame	Permeability, porosity, viscosity, frequency	Attenuation and dispersion
Squirt/local flow	Pore and microcrack scale	Pressure exchange between compliant and stiff pores	Crack compliance, pore geometry, pressure, viscosity	Strong local attenuation and dispersion
Mesoscopic WIFF	Above pore scale, below wavelength	Pressure diffusion between elastically different regions	Heterogeneity size, permeability, viscosity	Frequency-dependent Q and velocity
Patchy-saturation flow	Fluid-patch scale	Pressure exchange between regions containing different fluids	Patch size, saturation, fluid contrast, permeability	Strong P-wave attenuation and dispersion
Fracture-matrix flow	Fracture scale	Fluid exchange between fractures and porous matrix	Fracture compliance, connectivity, permeability	Attenuation, dispersion and possible anisotropy

These mechanisms are not necessarily mutually exclusive. Natural reservoir rocks may contain pores, cracks, fractures, and saturation heterogeneity simultaneously. Therefore, measured attenuation may represent the combined response of several relaxation processes rather than a single mechanism.

3.3 Patchy Saturation and Pressure Equilibration

Patchy saturation provides one of the clearest links between fluid saturation and seismic attenuation. In a partially saturated reservoir, water, oil, gas, or CO_2 may occupy spatially separated regions rather than forming a homogeneous mixture. These patches can develop different pore pressures when subjected to the same seismic compression because their effective compressibilities differ [13,19,20]. The contrast is particularly strong in gas-liquid systems. A gas-rich region is much more compressible than a water-rich region. Seismic compression therefore creates a pressure imbalance between the two patches, causing fluid-pressure diffusion through the connected pore network. Three dynamic regimes can be distinguished. At **low frequency**, the wave period is relatively long compared with the hydraulic equilibration time. Fluid pressure has sufficient time to redistribute between patches, and the rock approaches a relaxed, relatively compliant state.

Within the **transition or relaxation regime**, pressure redistribution occurs but cannot reach complete equilibrium during each wave cycle. Fluid movement is substantial and viscous losses become strongest. This regime is therefore associated with enhanced attenuation and rapid velocity dispersion.

At **high frequency**, the wave period becomes too short for significant pressure exchange. Individual patches behave more independently, and the rock approaches an unrelaxed, stiffer effective state.

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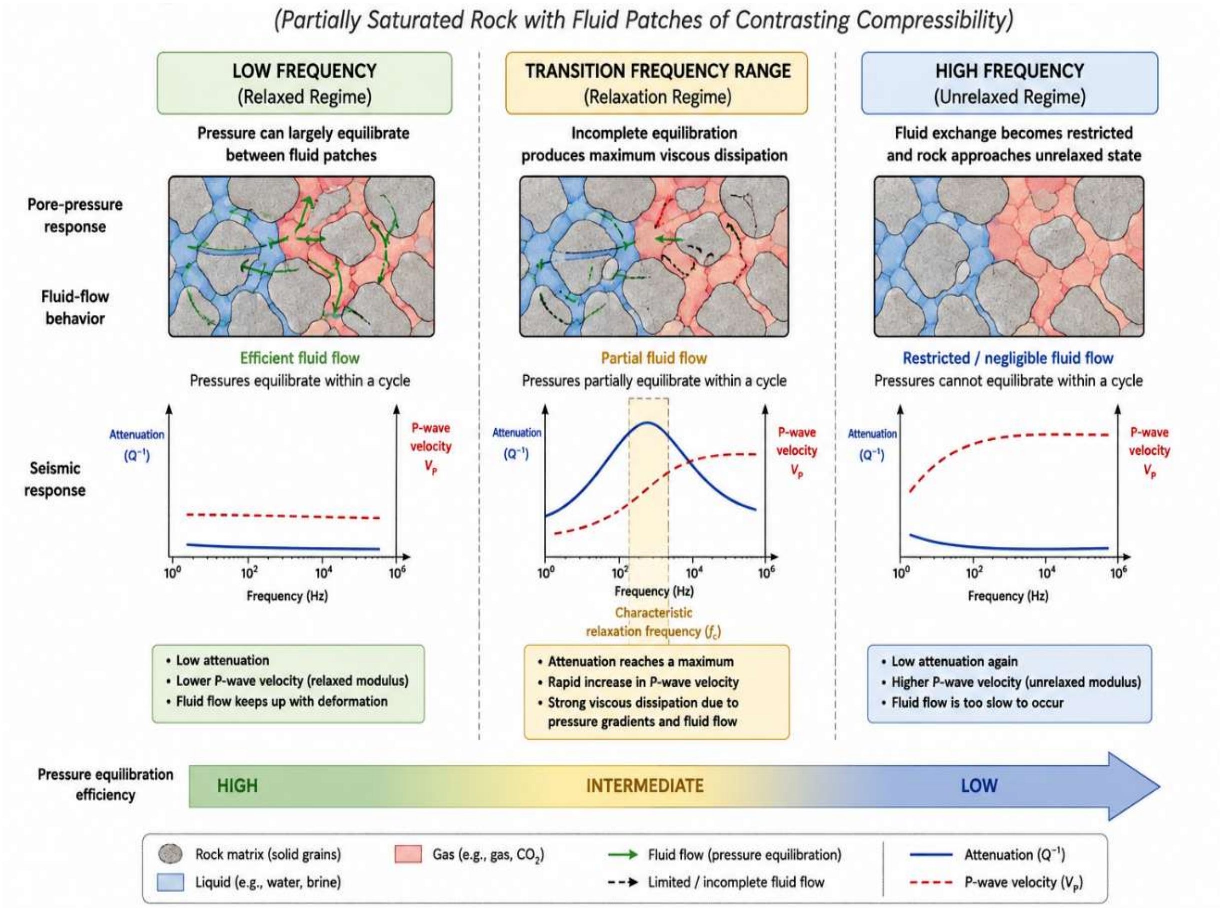

Figure 3.2. Patchy saturation and pressure equilibration across frequency regimes.

Patch size strongly controls this transition. Larger patches require fluid-pressure diffusion over longer distances and therefore generally shift the relaxation toward lower frequencies. Smaller patches equilibrate more rapidly and can shift the characteristic response toward higher frequencies [13,19]. Permeability and fluid viscosity exert similarly important controls. Higher permeability facilitates pressure diffusion, whereas higher viscosity slows fluid redistribution. Saturation geometry, connectivity, wettability, and capillary effects can further modify the hydraulic pathways. Consequently, two rocks with identical
average saturation can exhibit different attenuation and dispersion if their fluid-patch geometries differ. This is one of the principal reasons why seismic saturation estimation can be non-unique.

3.4 Frequency-Dependent Attenuation and Velocity Dispersion

Fluid-pressure relaxation produces a characteristic relationship between frequency, attenuation, and velocity. At low frequencies, pressure equilibration allows the rock to approach its relaxed elastic modulus. P-wave velocity is therefore relatively low.

As frequency approaches the characteristic relaxation frequency, fluid redistribution becomes increasingly out of phase with the applied deformation. Viscous losses increase and Q^{-1} reaches a maximum near the relaxation region. At still higher frequencies, insufficient time is available for substantial fluid exchange. The rock approaches its unrelaxed modulus, which is generally higher than the relaxed modulus. P-wave velocity therefore increases toward a high-frequency limit while attenuation decreases after passing through its maximum [12–14,18–20].

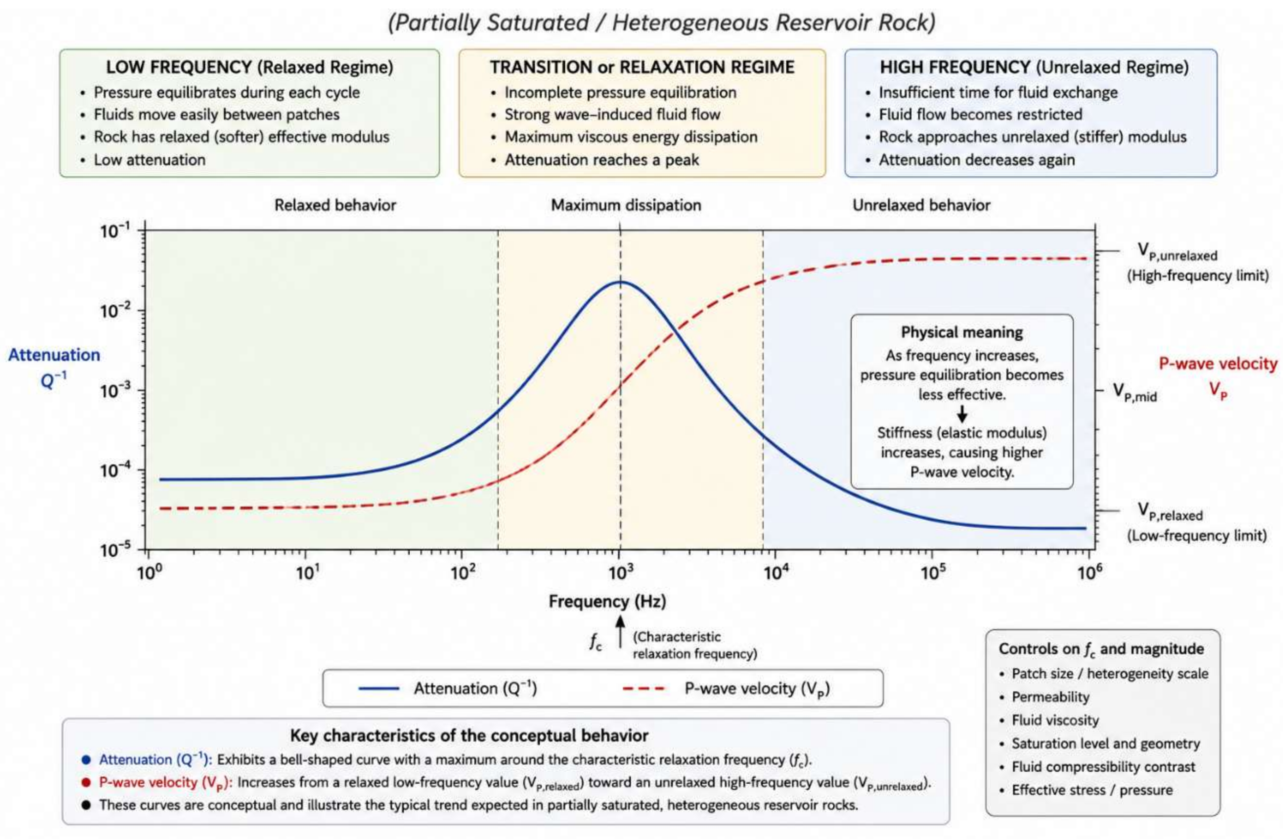

Figure 3.3. Conceptual relationship between attenuation and velocity dispersion.

This relationship has major implications for reservoir rock physics because different geophysical measurements occupy different frequency ranges. Surface seismic surveys commonly operate at relatively low frequencies, borehole sonic measurements at intermediate frequencies, and laboratory ultrasonic measurements at much higher frequencies. A velocity measured ultrasonically may therefore differ from the effective velocity observed by field seismic waves even when rock composition, pressure, and saturation remain unchanged. Direct extrapolation of laboratory measurements to reservoir conditions can consequently introduce errors unless dispersion is quantified. Attenuation measurements can help identify whether such dispersion is significant. If strong Q^{-1} occurs within or near the frequency range of interest, substantial modulus and velocity dispersion should also be expected.

3.5 Experimental and Numerical Evidence

Experimental evidence for fluid-dependent attenuation extends back several decades. Mavko and Nur [5] demonstrated significant attenuation in partially saturated rocks, while Winkler and Nur [6] emphasized the importance of pore fluids in seismic energy loss. Laboratory measurements by Toksöz et al. [7] and the associated mechanistic interpretation by Johnston et al. [8] further established the strong dependence of attenuation on saturation and rock properties. Murphy [10,11] showed that partial water and gas saturation can substantially alter acoustic properties in porous rocks. These studies provided important evidence that intermediate saturation states may exhibit behavior that cannot be represented simply by interpolation between dry and fully saturated end members. Later theoretical and numerical work clarified the physical mechanisms. Müller and Gurevich [13] modeled heterogeneous patchy saturation and demonstrated its effects on both velocity and attenuation. Pride et al. [14] developed a broader description of attenuation associated with wave-induced fluid flow, highlighting the importance of mesoscopic heterogeneity. Picotti et al. [16] studied numerically the

P-wave attenuation associated with slow-wave diffusion in partially saturated rocks. Masson and Pride [19] further studied the attenuation due to patchy saturation, and Rubino and Holliger [20] showed that heterogeneous partial saturation causes seismic attenuation and velocity dispersion. Experimental research has increasingly focused on directly measuring dispersion rather than relying only on ultrasonic velocities. Li et al. [24] showed that saturation can strongly affect elastic dispersion and attenuation in tight rocks, emphasizing that pore structure and low permeability can significantly modify the characteristic frequency response.

A particularly important advance is the integration of imaging with acoustic measurements. Chapman et al. [25] combined X-ray CT observations of fluid distribution with direct measurements and numerical simulations of attenuation and dispersion. Such approaches are valuable because they reduce uncertainty concerning the actual saturation geometry inside laboratory samples.

Table 3.3. Representative Studies of Saturation-Dependent Attenuation and Dispersion

Study	Method	Main focus	Key contribution
Mavko & Nur [5]	Laboratory	Partial saturation	Established strong attenuation associated with partial fluid saturation
Toksöz et al. [7]	Laboratory	Dry vs. saturated rocks	Quantified saturation-dependent seismic attenuation
Murphy [10,11]	Laboratory	Water/gas saturation	Demonstrated strong acoustic sensitivity to partial saturation
Müller & Gurevich [13]	Theoretical	Random patchy saturation	Linked fluid heterogeneity to velocity and attenuation
Pride et al. [14]	Theoretical	Wave-induced fluid flow	Established a physical framework for WIFF attenuation
Picotti et al. [16]	Numerical	Partial saturation	Linked slow-wave diffusion with P-wave attenuation
Masson & Pride [19]	Modeling	Patchy saturation	Quantified attenuation from patch-scale pressure diffusion
Rubino & Holliger [20]	Numerical	Heterogeneous saturation	Demonstrated coupled attenuation and velocity dispersion
Li et al. [24]	Experimental	Tight rocks	Showed saturation-dependent elastic dispersion and attenuation
Chapman et al. [25]	CT + experiment + simulation	Partial saturation	Directly linked fluid distribution with attenuation and dispersion

Together, these studies show a clear progression from identifying saturation-dependent attenuation experimentally to explaining it through physically based models and, more recently, directly connecting observed fluid geometry with seismic response.

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3.6 Integrated Controls on Attenuation and Dispersion

The magnitude and frequency of fluid-related attenuation cannot be predicted from saturation alone. Instead, several parameters operate together.

Saturation level determines the proportions of the different fluids, while **fluid contrast** controls the magnitude of pressure differences that can develop between regions. Gas-liquid systems therefore often generate stronger contrasts than liquid-liquid systems.

Saturation geometry and patch size determine the distance over which pressure diffusion occurs. **Permeability and fluid viscosity** control the rate of this redistribution, while **pore and crack geometry** influence local compliance and hydraulic connectivity. **Effective pressure** can modify cracks and grain contacts, changing both the elastic frame and fluid-flow pathways.

Finally, **measurement frequency** determines whether a particular pressure-relaxation mechanism is observed in its relaxed, transitional, or unrelaxed regime.

The overall process can therefore be represented as:

Fluid type and saturation
→ Spatial fluid heterogeneity
→ Pore-pressure contrasts
→ Wave-induced fluid flow
→ Viscous energy dissipation
→ Attenuation
→ Frequency-dependent elastic modulus
→ Velocity dispersion.

This framework explains why attenuation and dispersion are particularly valuable for partially saturated reservoirs. Velocity indicates the effective elastic state of the rock at a given frequency, whereas attenuation provides information about active pressure-relaxation processes. Their joint interpretation can therefore provide stronger constraints on reservoir fluid distribution than velocity alone.

For quantitative reservoir applications, however, these properties must be interpreted together with permeability, pore structure, effective pressure, and saturation geometry.

4. Reservoir Applications, Limitations, and Future Directions

4.1 Hydrocarbon Reservoir Characterization and Monitoring

Fluid-sensitive seismic properties provide important constraints on reservoir saturation and fluid movement. In hydrocarbon reservoirs, replacement among brine, oil, and gas modifies elastic properties, particularly P-wave velocity. Gas generally produces the strongest velocity response because its compressibility is substantially higher than that of reservoir liquids. However, velocity alone cannot uniquely determine saturation because lithology, pressure, pore structure, and fluid distribution may produce comparable seismic changes.

Attenuation and dispersion provide complementary information. While velocity reflects the effective elastic state of the rock, attenuation is sensitive to active pore-pressure relaxation and fluid mobility. Joint analysis of V_p, V_s, Q, and frequency-dependent velocity can therefore improve discrimination between fluid and rock-frame effects.

This approach is particularly relevant to time-lapse (4D) seismic monitoring. Production, water flooding, and gas injection modify both saturation and reservoir pressure. Repeated seismic surveys can track these changes, but reliable interpretation requires separation of pressure-induced frame effects from fluid-substitution effects. Incorporating attenuation and dispersion into conventional velocity-based analysis may provide additional constraints on the location and distribution of mobile fluids.

Pang et al. [23], for example, demonstrated the potential of seismic-Q-based rock-physics templates for estimating porosity and fluid saturation in carbonate reservoirs, illustrating the value of extending reservoir interpretation beyond conventional velocity attributes.

4.2 CO_2 Storage and Multiphase Reservoirs

Saturation-dependent seismic behavior is increasingly important for geological CO_2 storage. Injection of CO_2 into saline formations creates a multiphase CO_2-brine system in which the two fluids have strongly contrasting elastic properties. Replacement of brine by CO_2 generally reduces the effective bulk modulus and P-wave velocity, making seismic methods suitable for monitoring plume migration.

However, injected CO_2 is rarely distributed uniformly. Buoyancy, capillary pressure, permeability heterogeneity, fractures, and reservoir layering generate complex saturation patterns. These heterogeneous distributions can produce wave-induced fluid flow and associated attenuation and dispersion.

Consequently, combining velocity changes with attenuation and frequency-dependent information may help distinguish changes in average CO_2 saturation from changes in its spatial distribution. Similar principles apply to water flooding, gas injection, enhanced oil recovery, and underground gas storage.

A useful interpretation framework is therefore:

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Reservoir fluid change → saturation and pressure distribution → rock-physics response → velocity, attenuation and dispersion → reservoir monitoring.

4.3 Major Limitations and Sources of Uncertainty

Despite extensive theoretical and experimental development, quantitative interpretation remains difficult. A major limitation is that many models assume simplified pore geometries and idealized uniform or patchy fluid distributions. Natural reservoir rocks contain irregular pores, fractures, mineral heterogeneity, and saturation structures spanning several spatial scales.

Characteristic fluid-flow length is another major uncertainty. Patch size strongly influences the relaxation frequency, but it is rarely known accurately in field reservoirs. Multiple attenuation mechanisms, including Biot flow, squirt flow, mesoscopic WIFF, and fracture-related flow, may also operate simultaneously, making observed Q difficult to attribute to a single process. Scale and frequency differences create additional uncertainty. Laboratory ultrasonic measurements are obtained at much higher frequencies than conventional seismic data. If dispersion occurs between these frequency ranges, laboratory velocity cannot be directly extrapolated to field conditions. Pressure-saturation coupling is equally important. Production and injection change reservoir pressure as well as fluid saturation. Because effective pressure modifies grain contacts and compliant cracks, seismic changes attributed to fluid substitution may partly reflect mechanical changes in the rock frame.

Table 4. Key Challenges in Quantitative Saturation Interpretation

Challenge	Main implication
Complex saturation geometry	Identical average saturation may produce different seismic responses
Unknown patch/flow length	Creates uncertainty in predicted relaxation frequency
Multiple attenuation mechanisms	Makes interpretation of measured Q non-unique
Laboratory-field frequency gap	Ultrasonic properties may differ from field seismic properties
Stress-saturation coupling	Fluid and pressure effects can be difficult to separate
Complex pore structure	Simple models may perform poorly in carbonates, tight rocks and fractured reservoirs
Field attenuation estimation	Scattering and acquisition effects may be confused with intrinsic attenuation

4.4 Emerging Experimental and Modeling Approaches

Recent developments offer opportunities to reduce these uncertainties. One important direction is the integration of **three-dimensional imaging with rock-physics measurements**. X-ray CT and micro-CT can reveal actual fluid distributions inside rock samples rather than requiring idealized saturation assumptions. Chapman et al. [25], for example, combined X-ray CT, direct measurements, and numerical simulations to investigate attenuation and dispersion under partial saturation. **Digital rock physics** provides another useful approach. High-resolution pore images can be converted into numerical rock models in which fluid distribution, pressure diffusion, and elastic response are simulated directly. This allows systematic investigation of pore geometry, connectivity, wettability, and saturation pattern. Broadband laboratory measurements are also essential. Combining low-frequency forced-oscillation measurements, sonic-frequency methods, and ultrasonic experiments can help identify relaxation frequencies and

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bridge the large frequency gap between laboratory and field observations.

For reservoir-scale applications, rock physics should increasingly be coupled with multiphase-flow simulations:

Flow simulation → saturation and pressure fields → rock-physics transformation → predicted seismic response.

Such integration is especially valuable for 4D seismic monitoring and CO_2 storage because saturation and pressure evolve continuously in both space and time.

4.5 Future Research Priorities

Future research should move beyond treating saturation as only an average volumetric quantity. Greater emphasis is required on **three-dimensional saturation geometry, fluid connectivity, and characteristic patch size**, because these properties directly control pressure diffusion and frequency-dependent seismic behavior. Broadband measurements covering seismic-to-ultrasonic frequencies are needed to establish reliable relationships between laboratory and field observations. Simultaneous measurements of velocity and attenuation would be particularly valuable for constraining relaxation mechanisms.

Further studies are also required for **carbonates, tight rocks, fractured reservoirs, and unconventional formations**, where complex pore structures may invalidate assumptions derived from conventional sandstones. For geological CO_2 storage, future models should incorporate realistic CO_2-brine distributions, pressure evolution, capillary effects, and reservoir heterogeneity to improve quantitative monitoring of plume migration. Finally, physics-informed machine learning may provide a useful complement to conventional rock physics. Models incorporating velocity, attenuation, dispersion, porosity, permeability, pressure, and saturation could capture complex nonlinear relationships, but physical constraints are necessary to ensure that predictions remain meaningful outside the training dataset.

Table 5. Priority Directions for Future Research

Priority	Recommended development	Expected benefit
3D fluid imaging	CT/micro-CT characterization of saturation patterns	More realistic saturation models
Broadband measurements	Extend measurements across seismic, sonic and ultrasonic bands	Better laboratory-to-field scaling
Digital rock physics	Image-based pore-scale simulations	Improved understanding of fluid-flow mechanisms
Multiphysics modeling	Couple reservoir flow, pressure and seismic response	Improved 4D and CO_2 monitoring
Complex reservoir rocks	Expand studies of carbonates, tight and fractured rocks	Greater field applicability
Physics-informed AI	Combine machine learning with rock-physics constraints	Improved quantitative saturation prediction

Overall, future progress depends on integrating **realistic fluid distributions, broadband seismic measurements, pore-scale imaging, and coupled reservoir-rock-physics models**. Such integration can reduce the non-uniqueness of saturation interpretation and improve the use of velocity, attenuation, and dispersion for hydrocarbon production monitoring and geological CO_2 storage.

5. Conclusion

Fluid saturation exerts a fundamental influence on seismic wave propagation in reservoir rocks, but its effect cannot be described by saturation percentage alone. This review demonstrates that seismic velocity, attenuation, and dispersion are jointly controlled by fluid type, saturation level and distribution, pore structure, permeability, fluid viscosity, effective pressure, and measurement frequency. These parameters determine both the static elastic response of the saturated rock and the dynamic redistribution of pore fluids during seismic deformation.

P-wave velocity provides the strongest conventional indicator of fluid substitution because pore-fluid compressibility directly affects the saturated bulk modulus. Gas-liquid substitution generally produces a greater P-wave response than liquid-liquid substitution, whereas S-wave velocity is comparatively less sensitive and is influenced mainly through density and changes in the rock frame. However, partially saturated rocks may exhibit substantially different velocities at identical average saturation because fluid geometry controls pore-pressure communication. Thus, velocity-based saturation estimates require information about both rock properties and fluid distribution. Attenuation and dispersion provide additional sensitivity to the dynamic behavior of reservoir fluids. In heterogeneous and patchily saturated rocks, seismic deformation generates pore-pressure gradients that drive wave-induced fluid flow. Viscous resistance to this flow dissipates seismic energy and produces attenuation. At the same time, incomplete pressure equilibration causes the effective elastic modulus and seismic velocity to vary with frequency. Attenuation generally becomes strongest near the characteristic relaxation frequency, where fluid redistribution occurs but cannot fully equilibrate within a wave cycle. These relationships indicate that velocity, attenuation, and dispersion should be interpreted as **coupled seismic manifestations of fluid-rock interaction**. Joint interpretation can potentially reduce ambiguities that arise when saturation is estimated from velocity alone and may provide information about fluid mobility, saturation heterogeneity, and characteristic pressure-diffusion scales.

Important challenges nevertheless remain. Natural reservoirs contain multiscale pore structures and irregular fluid distributions that are poorly represented by idealized uniform or patchy models. Multiple attenuation mechanisms may operate simultaneously, while pressure changes can modify the rock frame independently of saturation. In addition, the large frequency difference between laboratory ultrasonic measurements and field seismic observations complicates direct application of experimental results to reservoir conditions. These limitations are particularly relevant to time-lapse hydrocarbon monitoring and geological CO_2 storage, where both pressure and multiphase-fluid distributions evolve continuously. Reliable quantitative interpretation therefore requires models that simultaneously consider saturation, pressure, frequency, and reservoir heterogeneity. Future progress should emphasize broadband measurements, three-dimensional imaging of fluid distributions, digital rock physics, and coupled multiphase-flow and poroelastic simulations. Integration of these approaches with field seismic observations can improve laboratory-to-reservoir scaling. Physics-informed data-driven methods may further support quantitative interpretation when constrained by realistic rock-physics relationships.

Overall, the key implication of this review is that **fluid saturation should be treated as a spatially heterogeneous and frequency-dependent rock-physics problem rather than simply as a volumetric pore-fluid fraction**. Incorporating saturation geometry and dynamic pressure equilibration into the joint interpretation of seismic velocity, attenuation, and dispersion provides a more physically complete framework for reservoir fluid characterization, production monitoring, and geological CO_2 storage.

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