

Impact of Asphaltenes, Sulphur and Calcium on Electrostatic Coalescer Performance

Technical report for crude-oil desalting and dehydration service

Scope	Generic refinery and upstream electrostatic coalescers handling water-in-crude emulsions
Prepared	17 July 2026
Basis	Published electrocoalescence research, operating literature and engineering synthesis

Central finding

Asphaltenes are a direct and often dominant barrier to droplet-film rupture. Total sulphur is usually an indirect descriptor and should not be used alone to predict coalescer performance. Calcium is highly consequential only after its form is known: brine calcium, calcium naphthenate and mineral solids require different responses.

Engineering note

This is a mechanism-based report, not a substitute for the coalescer vendor's operating envelope, site process-safety review or crude-specific laboratory testing.

Executive summary

An electrostatic coalescer succeeds when dispersed brine droplets are polarised, move together, drain the intervening oil film, merge into larger drops and then settle. Crude chemistry can interrupt any of these steps. The practical outcome is governed by the state of the interface, droplet size, oil viscosity and density, phase conductivity, solids, mixing history, residence time and field waveform—not by a single crude assay value [1–5].

In the Stokes regime, the idealised settling velocity is $v_s \approx \Delta\rho g d^2 / (18 \mu_o)$. Thus, increasing droplet diameter from 10 to 30 μm increases theoretical settling velocity ninefold, provided the drops actually coalesce and the assumptions remain valid.

Table 1. Relative impact on coalescer performance

Crude attribute	Direct mechanism	Expected impact	Overall judgement
Asphaltenes	Adsorb at water/oil interfaces; form aged, viscoelastic films; may flocculate with solids	Slower film drainage and rupture; smaller persistent drops; rag layer and water carryover	High direct risk
Total sulphur	No single mechanism: total S combines many chemically different species	Usually tracks other crude properties rather than controlling coalescence itself	Low direct / medium indirect risk
Calcium in brine	Changes aqueous conductivity and ion–interface interactions	Can alter electric response and film strength; normally leaves with separated water	Medium, crude-specific risk
Oil-soluble calcium	Calcium naphthenates can form interfacial gels/solids and resist ordinary water washing	Persistent Ca, rag/emulsion problems, deposits and downstream contamination	High risk when present

Source: engineering synthesis from [1], [3]–[12]. Risk describes mechanism potential, not a universal concentration threshold.

Priority actions

(1) Speciate calcium into water-extractable, oil-soluble and particulate fractions. (2) Treat total sulphur as context, while measuring conductivity at operating temperature, solids, TAN, SARA/asphaltenes and viscosity. (3) Use crude-specific bottle/electrocoalescence tests to tune demulsifier, temperature and mixing. (4) Trend electrical stability, interface quality and effluent quality alongside salt and water removal.

Conclusions at a glance

- **Asphaltenes:** the strongest direct chemical risk among the three variables. Content alone is incomplete; aggregation state, solvent quality, resins, acids and solids determine film strength.
- **Sulphur:** total sulphur is not a defensible control variable for coalescer voltage or demulsifier dose. Investigate specific sulphur-related pathways—especially H_2S /corrosion and iron-sulphide solids—only when corroborating evidence exists.

- **Calcium:** a high total-Ca result is ambiguous. Good salt and water removal with little Ca removal strongly suggests an oil-soluble or particulate fraction that normal electrocoalescence cannot transfer to water.
- **Interaction:** high asphaltene plus calcium and naphthenic acidity is the most concerning combination because divalent ions and calcium naphthenates can strengthen or create interfacial structures.

1. Process basis and performance criteria

1.1 What the electric field does

AC, DC or modulated fields polarise dispersed water droplets and create attractive motion. Collisions alone are insufficient: the thin oil film between two approaching droplets must drain and rupture before a larger droplet forms. Excess field strength can also elongate, rebound or fragment drops; waveform, frequency and conductivity therefore matter [1,2,5,13].

Once drops grow, gravity performs the final separation. Lower viscosity and a larger oil–water density difference increase settling rate. This is why a chemical effect cannot be separated from temperature, API gravity, residence time, wash-water rate, inlet distribution and mixing-valve shear.

1.2 What “performance” means

Performance dimension	Primary indicators	Failure signature
Dehydration	Inlet/outlet BS&W; water ppm or vol%; water-drop profile	Wet desalted crude; unstable outlet water
Desalting	Inlet/outlet salt or chloride; salt-removal efficiency	Salt remains even when bulk water appears low
Electrical stability	kV, current, power, trip count, field balance	High current, voltage collapse, arcing/trips or inability to hold setpoint
Hydraulic/interface quality	Interface level, rag thickness, residence time, level-control stability	Growing rag, level hunting, water entrainment or oil undercarry
Effluent quality	Oil and grease, suspended solids, COD, pH	Oily or solids-rich brine; wastewater upset

Source: conventional desalter/coalescer operating framework; metrics should be aligned to site and vendor specifications.

1.3 Scope boundary

The report concerns water-in-crude electrocoalescence. It does not treat downstream hydrodesulphurisation, calcium catalyst poisoning or crude-unit corrosion in detail, except where those

issues help diagnose coalescer behaviour. No universal ppm or wt% threshold is proposed because the response is strongly crude-, water-, temperature- and field-specific.

2. Impact of asphaltenes

2.1 Direct mechanisms

Asphaltenes are the most polar and aromatic portion of crude and contain heteroatoms and metals. A small interfacially active subfraction can adsorb irreversibly at the water/oil boundary. With time, that layer becomes more elastic and mechanically resistant. It then acts as a barrier to film drainage and rupture, so droplets collide but do not merge [3–5].

- **Interfacial film formation:** adsorbed asphaltene aggregates create a physical and viscoelastic shell around brine droplets.
- **Film ageing:** longer contact time before treatment can increase film rigidity; an aged emulsion can be harder to break than a fresh one at the same assay composition.
- **Flocculation and precipitation:** blend incompatibility or poor solvent quality can move asphaltenes from dispersed molecules/aggregates into flocs. Experiments show that flocculated asphaltenes reduce electrocoalescence rate [4].
- **Viscosity and density coupling:** asphaltene-rich crudes are often heavier and more viscous. These physical properties slow droplet approach and gravitational settling, adding to the interfacial effect.
- **Solids synergy:** asphaltenes can adsorb onto mineral or corrosion solids, making them oil-wet and capable of forming particle-stabilised interfacial layers. Across diverse crudes, solids have been strong predictors of emulsion stability [7].

2.2 Expected operating effects

Observation	Mechanistic interpretation	Confirmatory check
Water and salt carryover with stable electrical load	Rigid films or over-sheared small drops; electric attraction occurs but film rupture is slow	Microscopy/drop-size profile; bottle/electrocoalescence test; demulsifier screen
Persistent or growing rag layer	Asphaltene/solid-rich interfacial material accumulates faster than it resolves	Rag sampling: SARA, solids, metals, microscopy and water content
Poor performance after crude-blend change	Blend incompatibility has destabilised asphaltenes or changed conductivity/viscosity	Blend-ratio compatibility series; conductivity and viscosity at process temperature

Observation	Mechanistic interpretation	Confirmatory check
More voltage gives limited benefit or worsens performance	Film strength, rebound or secondary break-up —not insufficient field—is limiting	Controlled field test; compare current, drop size and outlet water
Demulsifier response plateaus	Dose has passed its useful window, chemistry is mismatched, or mixing/contact location is wrong	Dose-response curve including injection point and contact time

Source: [3–5,7]. Individual symptoms are non-unique; use the confirmatory checks before changing operation.

2.3 Why asphaltene wt% is not enough

Emulsion stability is not a monotonic function of bulk asphaltene content. Solvent aromaticity, resin-to-asphaltene balance, the fraction already adsorbed or precipitated, aqueous pH and ion composition all matter. Crudes with similar asphaltene wt% can therefore require different demulsifiers and field settings. Blend compatibility should be assessed at the actual blend ratios and temperatures rather than inferred from the individual crude assays [3,14].

2.4 Mitigation and control

1. **Protect asphaltene solvency.** Avoid untested blend changes and long residence in incompatible diluent regimes; screen blend ratios for precipitation and emulsion stability.
2. **Select demulsifier by crude-specific testing.** Evaluate water drop, oil dryness, interface quality and effluent oil—not water drop alone. Establish the dose-response plateau and the required contact time [4].
3. **Optimise temperature within the design envelope.** Higher temperature lowers viscosity and accelerates film drainage, but can also increase crude conductivity and electrical load [1].
4. **Tune mixing to a window.** Mixing must contact salts with wash water without generating a population of droplets so small that residence time and field strength are insufficient.
5. **Remove and characterise solids.** Upstream filtration, tank-bottom management and corrosion control can reduce particle-stabilised rag; any hardware or chemistry change requires site review.

3. Impact of sulphur content

3.1 Total sulphur is a poor mechanistic variable

Total sulphur collapses many different species into one number: hydrogen sulphide, mercaptans, sulphides, thiophenes, benzothiophenes, higher fused-ring compounds, elemental sulphur and sulphur incorporated in resins/asphaltenes. A long-running Bureau of Mines/API study identified 176 individual

compounds across 13 classes in four crudes [8]. These species do not share one interfacial or electrical behaviour.

Interpretation rule

A change in total sulphur should trigger a crude-slate review, not an automatic coalescer adjustment. Act only after determining whether conductivity, viscosity/density, asphaltenes, acids, water chemistry, H₂S/corrosion products or solids changed with it.

3.2 Credible direct and indirect pathways

Sulphur-related feature	Relationship to electrocoalescence	Engineering significance
Neutral organosulphur in the oil phase	Generally remains oil-soluble; bulk concentration does not quantify interfacial film strength	Low direct significance for coalescence
Sulphur within asphaltenes/resins	Contributes to molecular polarity/polarisability, but total S cannot isolate the small active interfacial fraction	Indirect; measure asphaltene/SARA and emulsion response
H ₂ S and mercaptans	May partition into water and affect corrosion/HSE; not established as the primary droplet-film barrier	Manage for safety and corrosion; do not treat total S as proxy
Iron-sulphide or other sulphide solids	Inorganic particles can accumulate at interfaces and contribute to stable rag/emulsions or deposits	Potentially high when solids are confirmed
Sulphate in wash/produced water	An aqueous ion and possible scale partner for calcium; chemically distinct from crude organic sulphur	Evaluate water analysis separately

Source: [7,8] and engineering inference. The strength of the total-sulphur-to-coalescence relationship is low because speciation is lost.

3.3 Expected operating effects

High-sulphur crude can appear difficult to desalt because many sour crudes also differ in API gravity, viscosity, asphaltenes, acids, metals and solids. That is confounding, not proof that sulphur caused the performance change. If total sulphur increases while conductivity, viscosity, SARA/asphaltenes, TAN, solids and water chemistry remain stable, little direct change in electrocoalescence should be assumed.

A sulphur-related investigation becomes warranted when a rise in H₂S/corrosion indicators or sulphide solids accompanies rag growth, oily effluent, grid fouling or unstable electrical load. Sample the rag and brine solids for mineralogy and metals; do not infer iron sulphide from total crude sulphur alone.

3.4 Mitigation and control

- Do not dose demulsifier or change voltage on total sulphur alone.
- Trend total sulphur as crude-slate metadata; pair it with conductivity at operating temperature, viscosity, density, SARA/asphaltenes, TAN and solids.

- Measure H₂S and corrosive sulphur species under the site's safety and corrosion programme; control upstream corrosion to limit corrosion-product solids.
- Analyse wash water for sulphate separately when calcium scaling is plausible. Organic sulphur in crude is not sulphate.

4. Impact of calcium

4.1 Calcium speciation controls the response

A total-calcium result combines fractions that behave very differently. Before diagnosing the coalescer, divide calcium into water-extractable ionic calcium, oil-soluble/organically associated calcium and particulate mineral calcium. Only the first fraction is expected to transfer readily into the separated wash-water phase.

Table 2. Calcium forms and expected behaviour

Calcium form	Where it resides	Effect on coalescer/desalter	Removal approach
Ca ²⁺ / CaCl ₂ in entrained brine	Aqueous droplets	Changes brine conductivity and ion-interface interactions; normally removed when water is coalesced	Adequate wash water, mass transfer, droplet growth and water separation
Calcium naphthenate / oil-soluble Ca	Oil phase and/or interface	Can create interfacial gels/solids, rag and deposits; ordinary desalting may remove little	Crude-specific calcium-removal chemistry to convert/extract Ca, plus compatible demulsification
Mineral/scale particles	Suspended solids or rag	Particle-stabilised interface, deposits, abrasion or fouling; contribution depends on wettability and size	Solids management, mineralogy, water compatibility and appropriate filtration/cleaning

Source: [6,9–12]. “Oil-soluble” is operational: confirm by a validated water-extraction or phase-partition method.

4.2 Brine calcium and the electric field

Dissolved salts make brine droplets conductive and enable strong polarisation. However, cation type and salinity also change the asphaltenic interfacial layer. Laboratory electrocoalescence work shows that cation identity and salinity can materially change emulsion stability, with divalent ions capable of producing stronger effects than monovalent ions in the tested systems [6]. The sign and magnitude are crude-specific; calcium concentration alone should not be converted into a universal voltage correction.

At the vessel level, excessive water in the electrode zone, high crude-phase conductivity, an elevated interface or conductive pathways can increase current and limit voltage. The correct response may be level, mixing, temperature, wash-water or waveform optimisation—not simply more voltage [1].

4.3 Oil-soluble calcium and calcium naphthenates

Naphthenic acids can react with calcium to form organic salts. Certain high-TAN crudes contain polyfunctional acids that form strong calcium-naphthenate gels or deposits at the oil/water interface. Field literature reports separation problems and hard deposits, while refinery literature notes that calcium associated with naphthenic acids is difficult to extract through ordinary desalting [9–11].

This creates a diagnostic trap: the coalescer may achieve good dehydration and chloride removal while total calcium remains high. In that case, electrical coalescence is doing its water-separation job; the remaining calcium lacks a favourable route into the water phase. Specialised chemistry can convert or complex the calcium into a water-soluble species, but must be tested for corrosion, emulsion, effluent and wastewater impacts [10–12].

A vendor case study illustrates—not guarantees—the potential: for a 22–26 °API crude with 50–100 ppm inlet calcium, a combined contaminant-removal and demulsifier programme increased reported calcium removal from 72% to 86% while maintaining >90% desalting and dehydration KPIs [12]. Site-specific economics and risk review remain essential.

4.4 Mitigation and control

1. **Speciate before treating.** Measure total Ca, water-extractable Ca, Ca in washed/dehydrated oil and solids-associated Ca. Add TAN and, where justified, targeted naphthenic-acid/ARN analysis.
2. **For brine calcium, optimise water contact and removal.** Review wash-water rate and quality, mixing-valve ΔP , droplet size, temperature, residence time and interface level.
3. **For oil-soluble calcium, screen conversion/extraction chemistry.** Confirm calcium transfer to water and test emulsion resolution, brine oil, corrosion, COD and downstream compatibility before field application.
4. **Control pH deliberately.** Lower pH can suppress naphthenate formation, but acidification may increase corrosion, alter chloride behaviour and burden wastewater. Use a site-approved window rather than a generic target.
5. **Check water compatibility.** Calcium-rich water mixed with sulphate- or carbonate-rich water can precipitate solids. Model and bottle-test the actual waters at temperature.

5. Interaction and risk matrix

The three assay variables are not independent. Their interactions often explain why a crude blend behaves differently from either component crude.

Combination	Mechanism	Operational consequence	Risk
Asphaltenes + Ca ²⁺ + naphthenic acids	Divalent-ion interaction and/or calcium-naphthenate interfacial structures	Very strong films or gels, rag, poor water drop and deposits	High
Asphaltenes + incompatible blend	Loss of solvency causes aggregation/flocculation; solids may become oil-wet	Sharp deterioration after blend change despite similar bulk assay	High
High total S + high asphaltenes	Total S partly resides in heavy polar material but does not identify the active fraction	Correlation can be mistaken for causation	Moderate diagnostic risk
High total S + sulphide solids	Confirmed solids can stabilise interfaces or foul equipment	Rag and effluent solids; possible electrical instability	High if confirmed
Ca-rich water + sulphate/carbonate water	Incompatible waters may precipitate mineral scale/solids	Solids loading, deposits and emulsion stabilisation	Medium-high
High temperature + conductive crude	Lower viscosity helps settling, but conductivity and current can rise	A useful temperature increase may be limited by electrical load	Medium

Source: synthesis from [1,4,6–11]. Interaction severity must be verified with the actual crude, water and operating temperature.

6. Diagnostic and monitoring programme

6.1 Minimum analytical package

Category	Measurements	Decision supported
Crude physical/electrical	API/density, viscosity at process temperature, conductivity versus temperature, BS&W, salt	Settling capacity, electrical loading and feed normalisation
Interfacial chemistry	Asphaltene wt%, SARA, resin/asphaltene ratio, TAN, blend compatibility, bottle/electrocoalescence response	Film-strength and blend-risk diagnosis
Calcium	Total Ca; water-extractable Ca; Ca after exhaustive wash; Ca in solids/rag; targeted ARN analysis if justified	Select water-wash optimisation versus calcium-removal chemistry
Sulphur-related	Total S as metadata; H ₂ S/mercaptans under safety programme; rag/brine-solids mineralogy including Fe/S	Separate crude-slate correlation from specific corrosion/solids pathway
Water chemistry	pH, conductivity/TDS, chloride, Ca, Mg, Na, sulphate, bicarbonate/alkalinity, suspended solids	Predict conductivity, naphthenate and water-compatibility effects
Operations	Flow, temperature, wash-water %, mixing ΔP, demulsifier dose/location, interface level, residence time, kV/current/power/trips	Connect chemistry to the actual operating state
Outputs	Desalted crude water/salt/Ca; brine oil and grease, TSS/COD/pH; rag thickness	Balance product, interface and wastewater objectives

Recommended package; select validated site methods and sampling points. Preserve hot samples or use procedures that prevent phase redistribution where necessary.

6.2 Pattern-based troubleshooting

Observed pattern	Most likely class of cause	First checks
High outlet water and salt; normal current	Tight interfacial film, too-small drops, inadequate demulsifier/contact or low temperature	Drop size, bottle/electrocoalescence test, mixing ΔP , temperature, dose/location
High current/trips; voltage will not hold	High conductivity, excessive water in field zone, high interface, water bridging or solids/deposits	Level calibration, inlet water, conductivity at temperature, grid condition, brine path
Low water/salt but high Ca remains	Oil-soluble or particulate calcium	Water-extractable versus residual Ca; TAN/ARN; solids digestion/mineralogy
Rag grows after blend change	Asphaltene incompatibility, solids synergy or altered acid/ion balance	Blend series, SARA/asphaltenes, solids, TAN, Ca speciation, water chemistry
Total S changes without other symptoms	Crude metadata change only	Confirm physical properties, conductivity and interfacial tests before action
Total S rises with rag and Fe/S-rich solids	Corrosion/sulphide-solids pathway is plausible	Rag/brine mineralogy, corrosion monitoring and upstream source review

Diagnostic matrix; causes are not mutually exclusive. Change one controlled variable at a time where practicable.

6.3 KPI calculations

Use consistent, flow-weighted sampling and define the analytical basis. Recommended calculations are:

- Dehydration efficiency = $100 \times (\text{water_in} - \text{water_out}) / \text{water_in}$
- Desalting efficiency = $100 \times (\text{salt_in} - \text{salt_out}) / \text{salt_in}$
- Calcium removal = $100 \times (\text{Ca_in} - \text{Ca_out}) / \text{Ca_in}$; report separately for total and water-extractable calcium
- Electrical stability = time at required voltage, normalised current/power, and trips per operating day
- Interface/effluent = rag thickness or inventory, brine oil and grease, suspended solids and level variability

A concentration-only comparison can mislead when crude rate, wash-water rate or BS&W changes. Where possible, close calcium, salt, water and solids mass balances across the vessel.

7. Recommended implementation plan

7.1 Baseline and classify

1. Stabilise and document the operating state for representative crude runs. Capture feed blend, temperatures, flows, interface, electrical data, mixing and chemical dose with synchronised samples.
2. Classify the limiting regime: interfacial-film limited, viscosity/settling limited, electrically limited, hydraulic/level limited or contaminant-transfer limited.
3. Speciate calcium and characterise rag/solids before selecting chemistry. Treat total sulphur only as contextual information.

7.2 Laboratory screening

Use the actual crude blend and actual wash/produced water at representative temperature. A screening design should vary one or two factors around the current condition: demulsifier family/dose and contact point, temperature, mixing energy, wash-water rate/pH, field waveform where a bench electrocoalescence cell is available, and calcium-removal chemistry when oil-soluble Ca is confirmed. Measure oil dryness, salt/Ca transfer, interface quality, brine oil and electrical response.

7.3 Controlled field trial

Trial phase	Controlled change	Acceptance criteria
A. Baseline	No intentional change; establish variability and sampling lag	Stable mass balance and electrical/hydraulic state
B. Chemistry	Selected demulsifier or calcium-removal programme within approved range	Improved water/salt/Ca objective without brine-oil, corrosion or wastewater penalty
C. Operating conditions	One approved mixing or temperature step at a time within vendor envelope	Larger effective drop/removal gain without current/trip or effluent deterioration
D. Confirmation	Return-to-baseline or repeat best condition	Reproducible improvement beyond baseline variation

Any field change requires the site's management-of-change, process-safety and vendor constraints. Do not trial high-voltage or reactive chemistry outside approved procedures.

7.4 Control-knob trade-offs

Control knob	Potential benefit	Principal trade-off
Temperature	Lower oil viscosity; faster film drainage and settling	Higher crude conductivity/current; vapour pressure and energy limits

Control knob	Potential benefit	Principal trade-off
Mixing ΔP	Better salt/wash-water mass transfer	Smaller droplets and harder separation if over-mixed
Wash-water rate	More dilution/extraction capacity	Higher hydraulic load, field-zone water and effluent volume
Demulsifier dose	Displaces/weakens interfacial film	Dose plateau, overdosing, brine-oil or downstream effects
Acid/complexant for Ca	Converts oil-soluble Ca to extractable form	Corrosion, emulsion, COD, effluent and chemical-compatibility risk
Voltage/waveform	More droplet attraction and collision when field-limited	Rebound, fragmentation, current limitation or trips
Interface level	Correct weak/strong field exposure and residence	High level risks electrical bridging; low level risks oil undercarry

8. Conclusions

Asphaltenes have the clearest direct negative impact on electrostatic coalescence. Their interfacial adsorption, film ageing and flocculation can prevent droplet merger even when the electric field produces frequent collisions. The effective risk depends more on interfacial state and crude compatibility than on wt% alone.

Total sulphur does not provide a unique coalescence mechanism and is usually an indirect indicator of crude family. It should remain in the assay and trend set, but decisions should be based on the variables that act on the coalescer: conductivity, viscosity/density, asphaltenes/resins, acids, solids and water chemistry. Specific sulphur-related pathways require evidence of H₂S/corrosion or sulphide solids.

Calcium is potentially severe but only after speciation. Brine calcium is removed with the water when mass transfer and coalescence are effective. Oil-soluble calcium naphthenates can stabilise interfaces, form deposits and remain in desalted crude despite good dehydration. They require conversion/extraction chemistry and a tightly controlled compatibility programme rather than a simple voltage increase.

Recommended decision rule

When performance declines, diagnose the limiting mechanism first. If water/salt removal is poor, focus on films, droplet size, viscosity, conductivity, hydraulics and field stability. If water/salt removal is good but calcium persists, focus on calcium speciation and transfer chemistry. Do not use total sulphur as the deciding variable in either case.

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Evidence limitations

- Laboratory DC-cell and microfluidic studies clarify mechanisms but do not set universal plant-scale limits for AC or modulated-field equipment.
- Vendor case studies demonstrate feasibility in a specific unit and should not be treated as guaranteed performance or an independent benchmark.
- The direct effect of total sulphur on electrocoalescence is not well isolated in the literature; the report therefore gives greater weight to species-level chemistry and to measured conductivity, solids and interfacial behaviour.
- Calcium-ion effects vary with crude acids/asphaltenes, pH, salinity and temperature. Site testing is required before setting a wash-water or pH target.